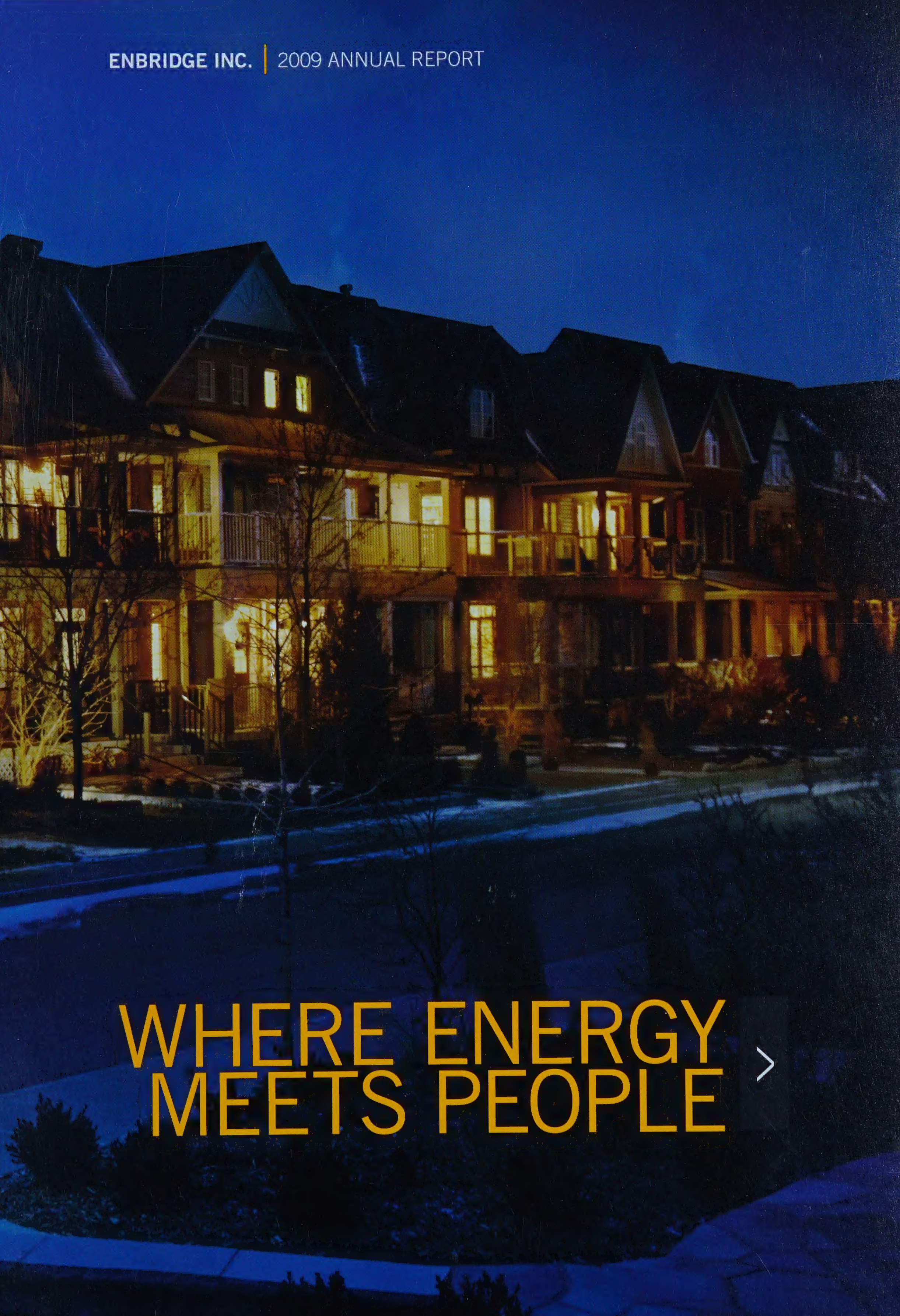
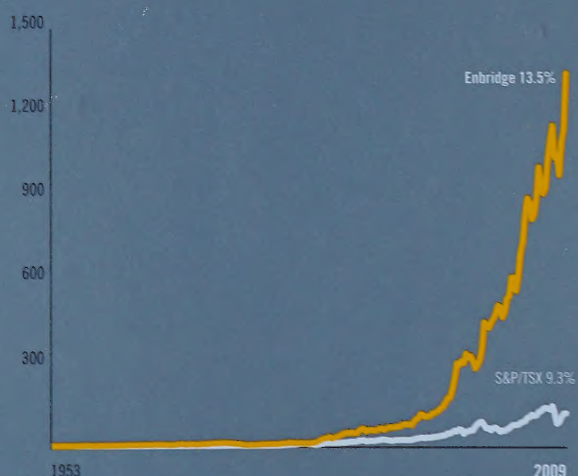
ENBRIDGE INC. | 2009 ANNUAL REPORT



WHERE ENERGY MEETS PEOPLE

WE ARE IN THE BUSINESS OF DELIVERING VALUE TO SHAREHOLDERS

Three key features guide our success: Growth. Income. Reliability. It's a powerful combination that has delivered success few companies can match.



Total Shareholder Return

(Total Return Index March 1953=1)

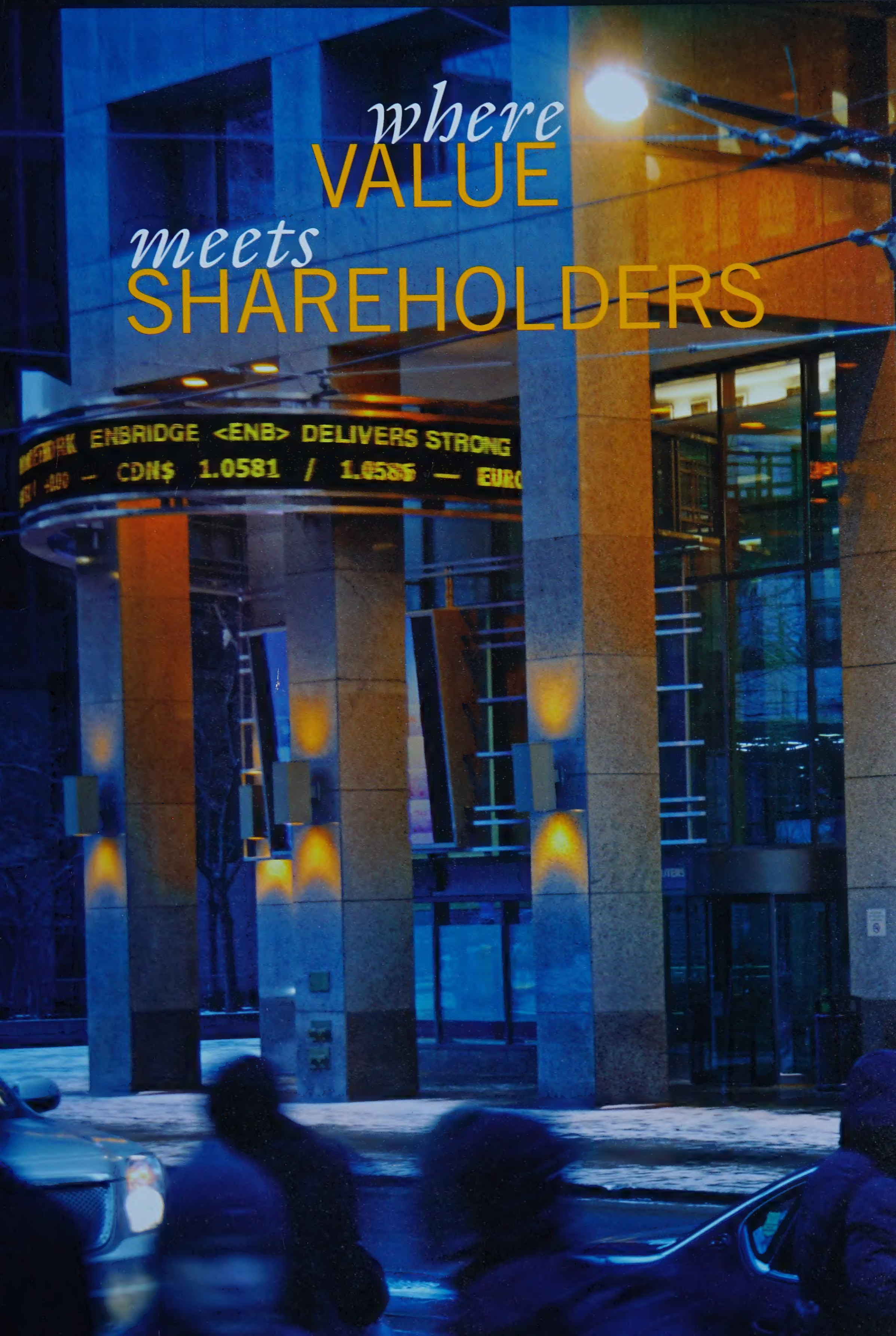
Since inception, we have achieved a 13.5% average annual return to shareholders and we are focused on maintaining this track record.

The global recession in 2009 devastated returns for most companies. Not Enbridge. With adjusted earnings per share growth of 25% in 2009, Enbridge delivered its best year ever, with strong performance across all its operations and new projects continuing to come into service on time and on budget.

Value At the end of 2009, the value of Enbridge's equity market capitalization stood at $18.4 billion, one of the largest corporations in Canada.

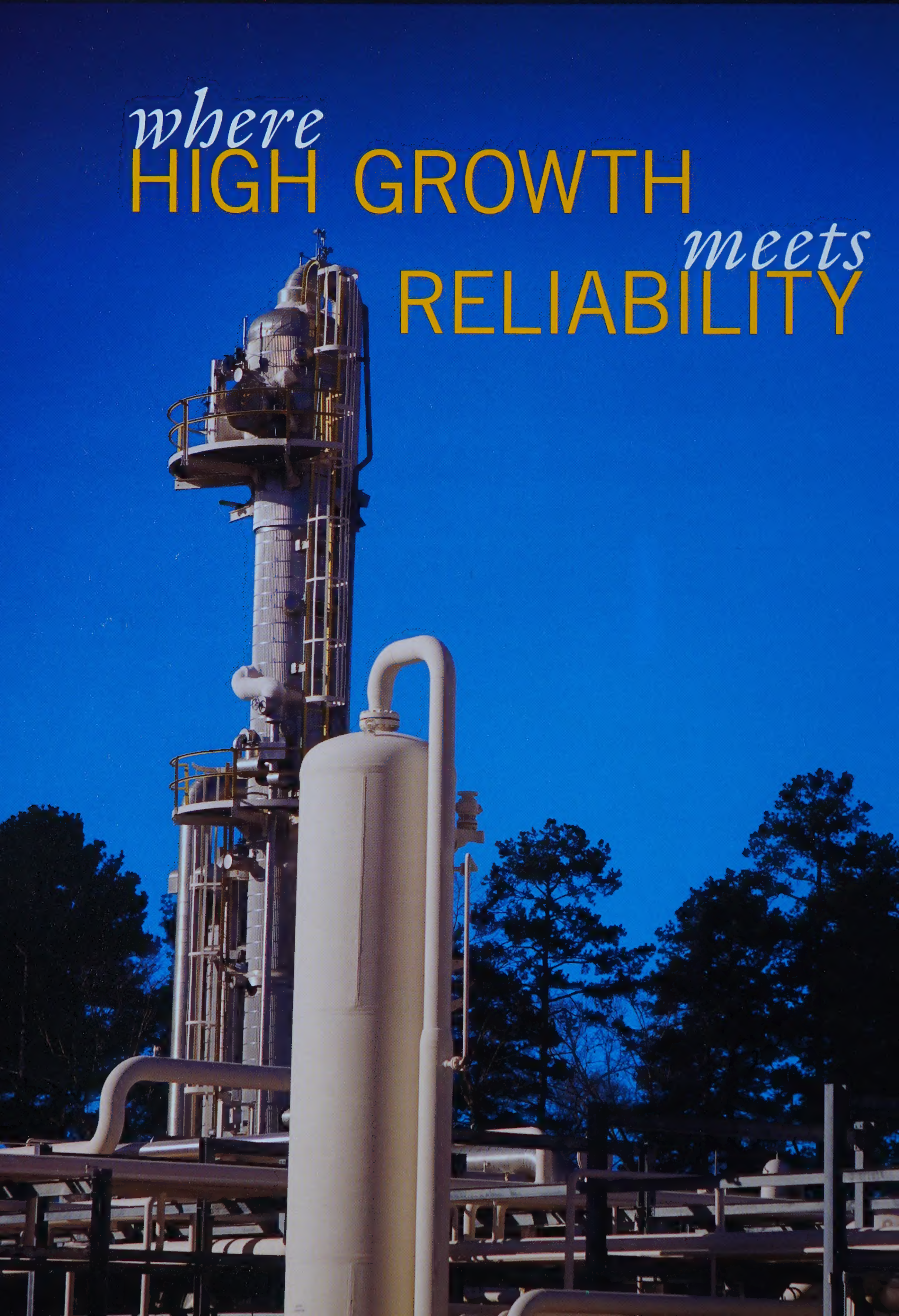
Shareholders An investment of $1.00 in Enbridge in March 1953 would have been worth approximately $1,300 at the end of 2009.

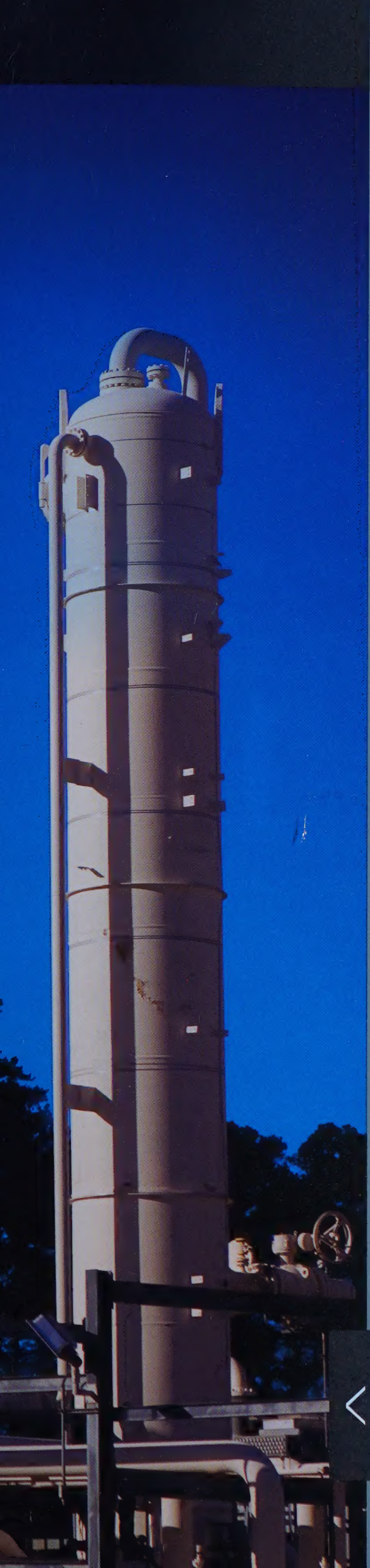
where VALUE *meets* SHAREHOLDERS



High Growth $12 billion in new Liquids, Gas and Green projects in service or expected to be in service 2008 to 2011; $5 billion secured post-2011; $30 billion in new opportunities.

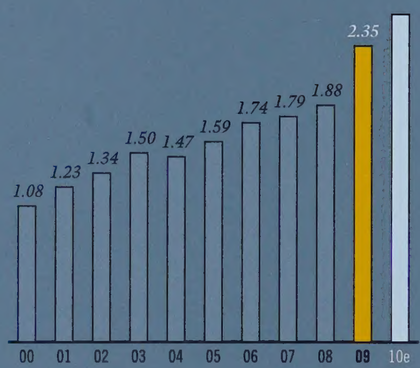
Reliability Over the last 10 years—including the recent global recession and financial crisis—Enbridge has consistently grown earnings.





AN INVESTMENT IN ENBRIDGE GROWS RELIABLY

At Enbridge you can benefit from a reliable investment while still enjoying the steady growth few companies can match. In 2009, Enbridge achieved record adjusted earnings per share growth of 25%.



Adjusted Earnings per Share

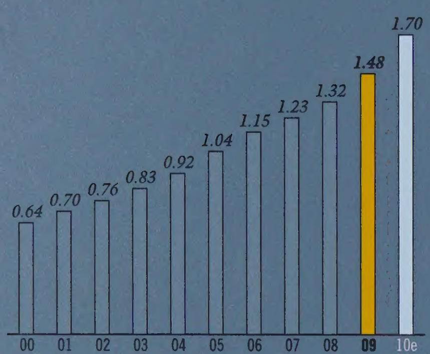
(Canadian dollars per share)

The diversity of Enbridge's businesses contributes to the reliability of our growth. Adjusted earnings per share are expected to grow by about 11% in 2010 and are targeted to grow by 10% per year on average into the second half of the decade.

Enbridge's large network of natural gas gathering, treating, processing and transmission facilities in the southern U.S. is well positioned for growth arising from the region's prolific shale gas plays.

AN INVESTMENT IN ENBRIDGE PAYS HANDSOME DIVIDENDS

Our record is unmatched. The 15% dividend increase announced in December 2009 was our 15th consecutive annual increase. Over the last decade, Enbridge's dividend growth has significantly outperformed that of our peers. We are focused on continuing this performance.



Growing Dividends

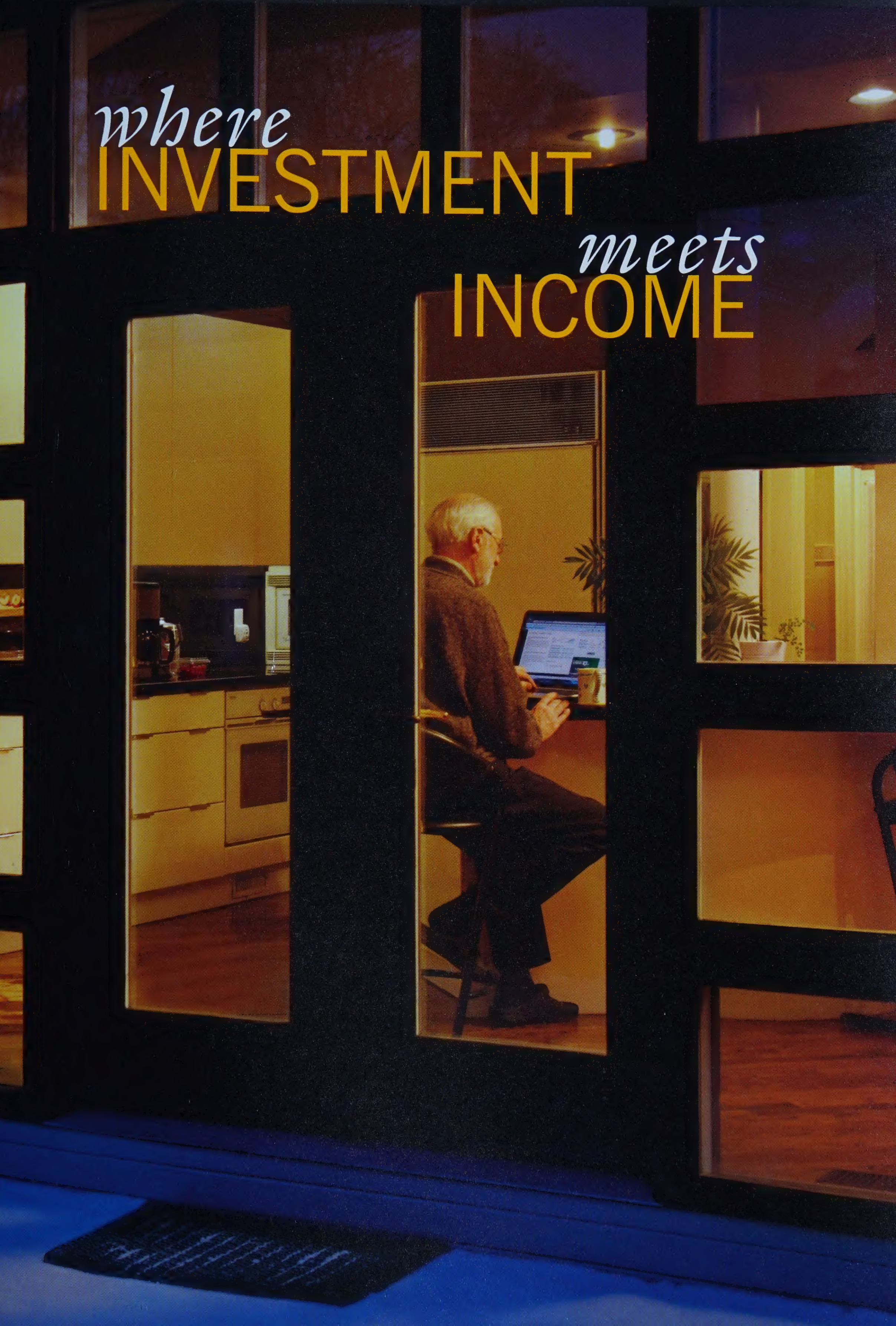
(Canadian dollars per share)

We aim to pay out 60 to 70% of our adjusted earnings as dividends to our investors. Dividends have increased, on average, approximately 10.3% annually over the last decade.

Enbridge has delivered solid income growth for shareholders since its inception in 1953. Our shareholders can continue to count on solid income performance with dividends tracking earnings growth. Enbridge common shares trade on the Toronto and New York stock exchanges under the symbol ENB.

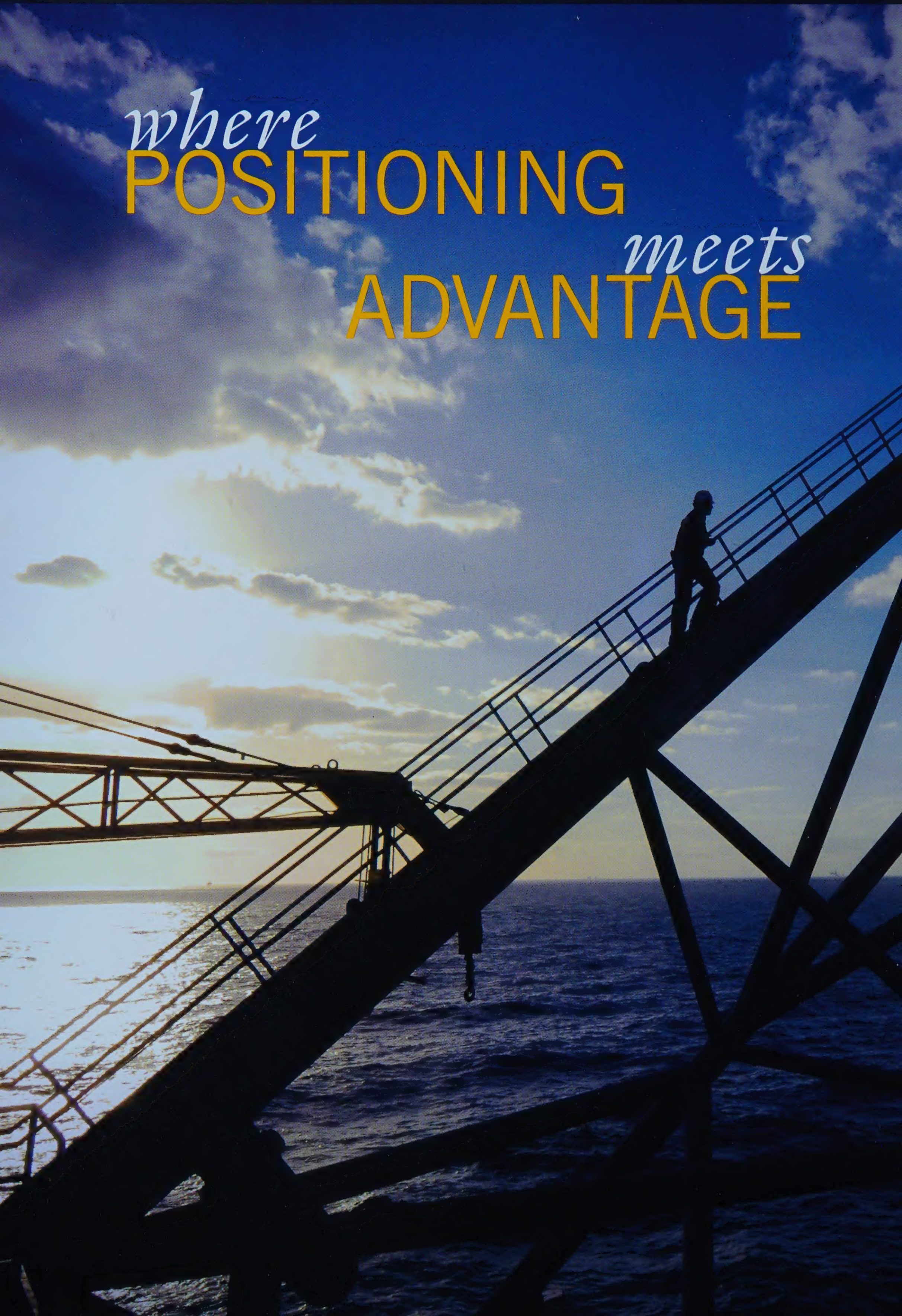
Investment Enbridge common shares offer a competitive dividend yield of 3.5%, making it an attractive investment for income-oriented investors.

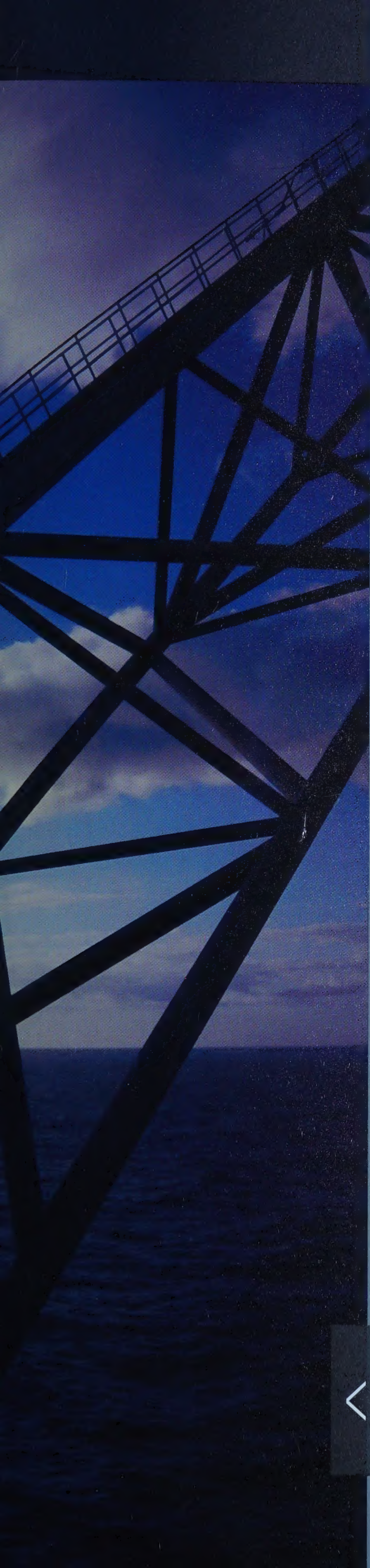
Income Enbridge has paid, and consistently increased common share dividends since inception in 1953. Based on estimated 2010 dividends, the annual increase has averaged 10%.



Positioning Our continent-wide energy delivery network is ideally located to serve the newest and most prolific opportunities—oil sands, shale gas and deepwater Gulf of Mexico.

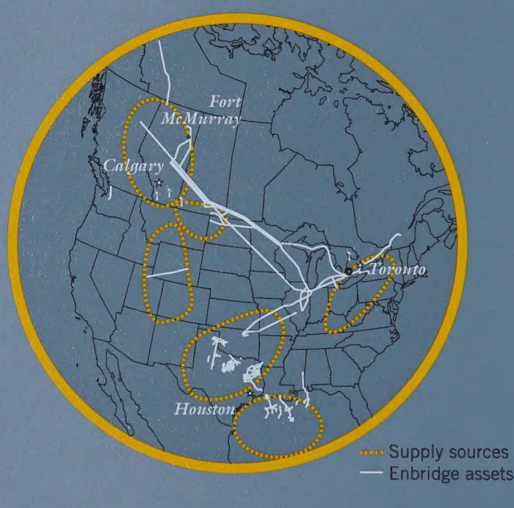
Advantage Our technical expertise and track record for developing projects on time, on budget and safely are distinct competitive advantages.





WE CONNECT VITAL SOURCES OF SUPPLY WITH REFINERS AND CONSUMERS ACROSS THE CONTINENT

We are ideally positioned for growth. Our existing infrastructure is located in strategic geographical locations, which puts us in a strong position to deliver energy to the fastest-growing North American and global markets.



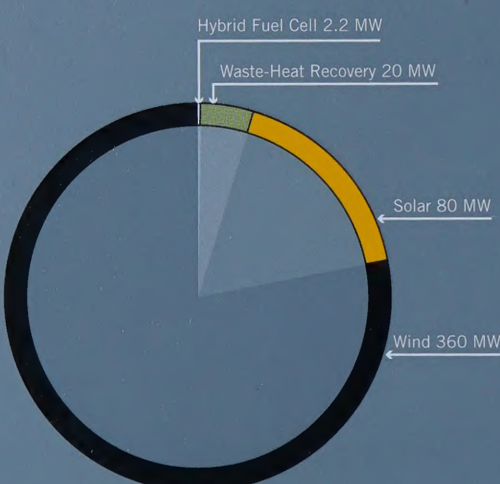
Geographic Reach

Enbridge is expanding its far-reaching energy delivery network to help ensure North Americans always have access to secure and reliable sources of energy.

Enbridge serves a majority of the deepwater platforms in the Gulf of Mexico. On the strength of our extensive presence, we now transport about 50% of Gulf deepwater gas production and are capturing new gas gathering and crude oil transportation opportunities serving the region's ultra deepwater developments.

OUR GREEN ENERGY INVESTMENTS GENERATE ATTRACTIVE RETURNS

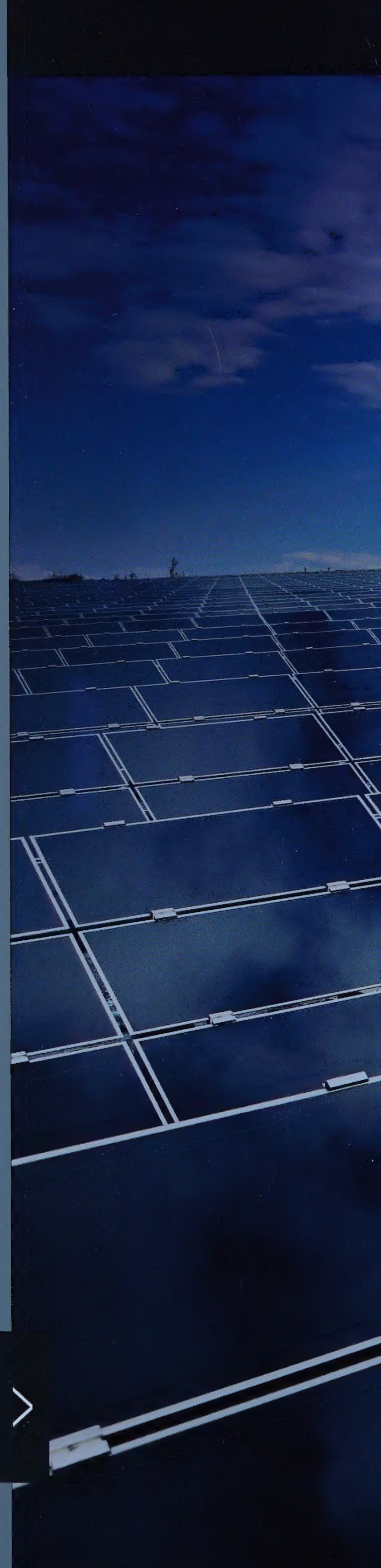
Investing in green energy is good for the environment and great for our investors. Our renewable assets follow the same reliable business model as our traditional energy assets and are part of the reason you can expect reliable income growth as we move forward.



Green Power Generation

Enbridge's Green Energy footprint is small, but diversified and growing. Our interests in renewable and alternative power generation in operation and under construction have capacity to generate enough electricity to serve more than 150,000 homes.

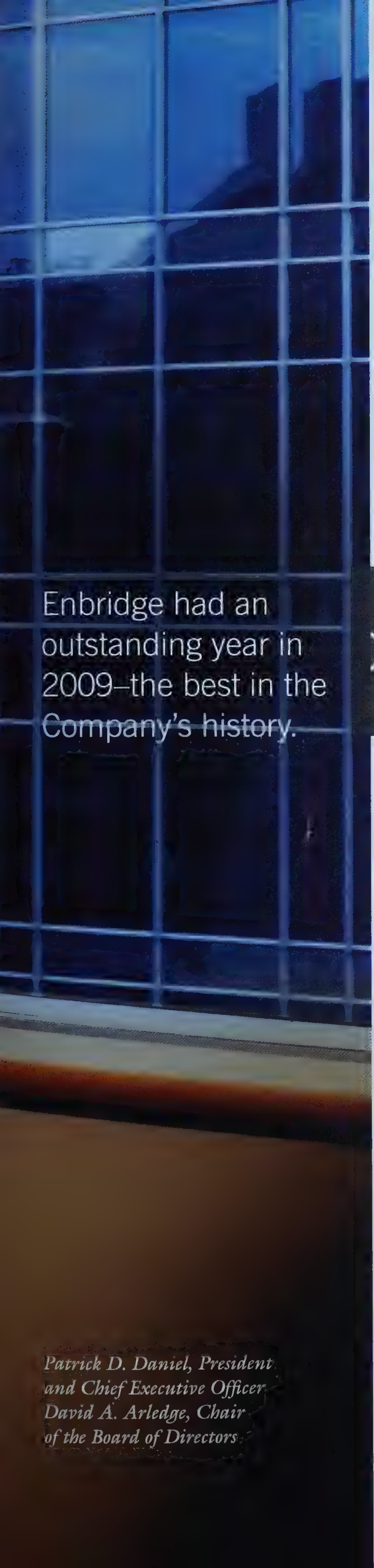
Enbridge's 20-MW Sarnia Solar Project, already one of the largest photovoltaic solar energy facilities in North America, is adding another 60 MW of capacity in 2010 to supply more emissions-free power to the Ontario grid.



Renewable Enbridge now has interests in over 460 MW of emissions-free green power capacity—wind, solar, waste-heat recovery and hybrid fuel cells.

Return Through the use of long-term power purchase agreements and fixed price contracts, our renewable energy projects can deliver stable cash flows and attractive returns.


where
PAST SUCCESS
meets
THE FUTURE



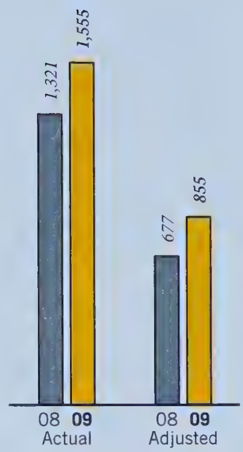
Enbridge had an outstanding year in 2009–the best in the Company's history.

Patrick D. Daniel, President and Chief Executive Officer
David A. Arledge, Chair of the Board of Directors

2009 Earnings

(millions of Canadian dollars)

Enbridge delivered adjusted earnings at the top end of the Company's 2009 guidance range.



LETTER TO SHAREHOLDERS

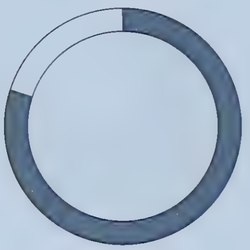
Enbridge maintained its reliable performance through the global recession, and is now stronger than it has ever been and poised for continued steady growth.

We had an outstanding year in 2009, delivering the best results in the Company's history and building on a more than 50-year track record of exceptional performance. Adjusted earnings per share increased 25% to $2.35 per common share. Actual earnings increased 18% to $1,555 million, or $4.27 per common share, compared with $1,321 million, or $3.67 per common share, in 2008. Enbridge's strong earnings throughout the global recession are a testament to Enbridge's reliable business model, which delivers steady financial performance.

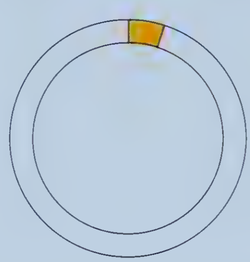
Reliable Business Model

Our reliable business model results in highly predictable earnings.

80% of earnings are from volume-insensitive, long-term commercial arrangements.



Commodity prices, interest rates and foreign exchange rates in combination **should not impact Enbridge's earnings by more than 5%.**



95% of revenue is from a low-risk, diversified base of large, reputable investment-grade customers.

Our Liquids Pipelines, Gas Transportation and Green Energy businesses are all well positioned to contribute further reliable growth in 2010 and well beyond, with a large array of attractive investment opportunities under development and coming to fruition at a steady pace. We have built up ample financial capability and liquidity reserves to take full advantage of these opportunities.

Based on the midpoint of our guidance, we expect adjusted earnings per share will grow by approximately 11% this year over 2009, and as a result Enbridge's Board of Directors has raised the 2010 dividend by 15%. This represents the Company's 15th consecutive annual dividend increase. Over the past decade, Enbridge has delivered a 10% compound annual growth rate on its dividend—well ahead of the broader market and our peers.

Enbridge's earnings are targeted to grow on average by 10% per year.

We are targeting Enbridge's earnings per share to grow on average by 10% per year into the second half of this decade with dividends increasing in parallel.

Enbridge's strong performance in 2009, and the continued solid growth we expect to deliver in 2010 and beyond, are the direct result of the $4.5 billion in commercially secured growth projects we brought into service in 2008 and 2009 and the additional $7 billion in projects expected to come into service in 2010 and 2011. Moreover, we have secured over $5 billion of new projects for post-2012 and have an additional inventory of opportunities of approximately $30 billion currently under development across our Liquids Pipelines, Natural Gas and Green Energy businesses.

LIQUIDS PIPELINES

In Liquids Pipelines in 2009, commercial operations began on the second phase of the Southern Access Project. Combined with the first phase, Southern Access has increased capacity on our mainline by 400,000 barrels per day (bpd). We also completed both our Spearhead Expansion Project to extend the reach of Canadian crude oil into the North American storage hub at Cushing, Oklahoma, and the Line 4 Project, which extended Line 4 of our mainline system from Hardisty, Alberta, back to Edmonton. In the first quarter 2009, we brought two key components of the Southern Lights diluent project into service: a new 20-inch light sour (LSr) crude oil pipeline from Cromer, Manitoba, to Clearbrook, Minnesota, and modifications to existing Line 2. Combined, the LSr Pipeline and Line 2 modifications increase southbound capacity on the Enbridge mainline and will permit Line 13 to be taken out of service and reversed for diluent service in 2010.
We complemented those pipeline projects with

Financial Highlights

Year ended December 31,	2009	2008	2007
(millions of Canadian dollars, except per share amounts)			
Earnings per Common Share	**4.27**	3.67	1.97
Adjusted Earnings per Common Share	**2.35**	1.88	1.79
Dividends per Common Share	**1.48**	1.32	1.23
Total Common Share Dividends Declared	**555**	489	453
Return on Average Shareholders' Equity	**22.2%**	22.2%	13.6%
Debt to Debt Plus Shareholders' Equity	**66.2%**	66.6%	66.5%

the expansion of storage facilities, including adding 7.5 million barrels of capacity to our Hardisty contract terminal, making that facility one of the largest storage facilities in North America.

Liquids Pipelines will continue to deliver strong growth in earnings and cash flow in 2010 as we start up two of our largest projects, Alberta Clipper, the largest mainline expansion in Enbridge's history, and the unique Southern Lights Pipeline from Chicago to Edmonton that will deliver diluent to western Canada. We will also strengthen our competitive advantage as the largest pipeline operator in the important Bakken region as Enbridge Income Fund and Enbridge Energy Partners, L.P. complete expansions of their Saskatchewan and North Dakota systems, respectively, and work to secure commercial support for subsequent phases.

Enbridge has secured a number of attractive opportunities to expand our oil sands regional infrastructure.

Looking beyond 2010, we're encouraged by signs of renewed activity in the Alberta oil sands. Enbridge has secured a number of attractive opportunities to expand our oil sands regional infrastructure, including the Woodland Pipeline to serve the Kearl Lake oil sands project, additional pipeline and terminal facilities to support expansion of the Christina Lake enhanced oil project and additional volumes on our Waupisoo Pipeline from the Leismer oil sands project.

We enjoy a very strong competitive position in the oil sands region and we're actively pursuing further opportunities to connect new production through expansion of our existing systems and the construction of new pipelines. We also continue to make progress on our Northern Gateway Project, a proposed twin pipeline system running from near Edmonton, Alberta, to a new marine terminal in Kitimat, British Columbia, to export crude oil and import condensate. Northern Gateway would provide an outlet for bitumen and synthetic crude to both Asia and California markets, opening up a completely new market to Alberta producers and ensuring that they maximize the value of Canadian crude. We anticipate filing our regulatory application for Northern Gateway with the National Energy Board in early 2010.

NATURAL GAS AND OFFSHORE

Growth opportunities for our Natural Gas business have never been better.

In 2009, Enbridge Offshore Pipelines secured two attractive deepwater projects in the Gulf of Mexico: the US$500 million Walker Ridge Gas Gathering System and the US$250 million Big Foot Oil Pipeline. There are a number of additional deepwater projects under development. Our extensive systems

Operating Highlights

	2009	2008	2007
Liquids Pipelines—Average Deliveries *(thousands of barrels per day)*			
Enbridge System [1]	**2,061**	2,030	2,005
Enbridge Regional Oil Sands System [2]	**259**	202	164
Spearhead Pipeline	**121**	110	103
Olympic Pipeline	**280**	291	284
Natural Gas Delivery and Services			
Gas Pipelines—Average Throughput Volumes *(millions of cubic feet per day)*			
Alliance Pipeline US	**1,601**	1,609	1,598
Vector Pipeline	**1,334**	1,321	1,034
Enbridge Offshore Pipelines	**2,037**	1,672	2,060
Enbridge Gas Distribution			
Volumes *(billions of cubic feet)*	**408**	433	440
Number of active customers [3] *(thousands)*	**1,937**	1,898	1,861

in the Gulf and strong technical and operating capabilities position us well to capture new oil and gas opportunities.

Our onshore natural gas assets are also very well positioned to take advantage of the many emerging shale gas plays in both Canada and the United States. In 2009 we advanced a number of projects, including our proposed LaCrosse Pipeline connecting the prolific Haynesville shale in Texas and Louisiana to key markets.

Enbridge Gas Distribution (EGD) continued in 2009 to improve its already steady and reliable performance, achieving an increase in its return on investment in the second year of its five-year incentive regulation regime. Even in a down economy, EGD is adding between 30,000 and 45,000 new customers a year and now has close to two million customers, making it one of the fastest growing utilities in North America.

GREEN ENERGY

In our Green Energy business, we brought our 190-MW Ontario Wind Power Project—the second largest wind farm in Canada—into full commercial operation in 2009. We also completed construction and testing of the first phase of the 20-MW, $100 million Sarnia Solar Energy Project, and that project is now supplying emissions-free power to the Ontario grid. We are also moving ahead with a $300 million expansion of the Sarnia facility to add another 60 MW of capacity this year. Once completed, the Sarnia Solar Project will be one of the largest photovoltaic solar energy facilities in North America.

Enbridge's Green investments build on our excellent track record in environmental stewardship and emissions reductions.

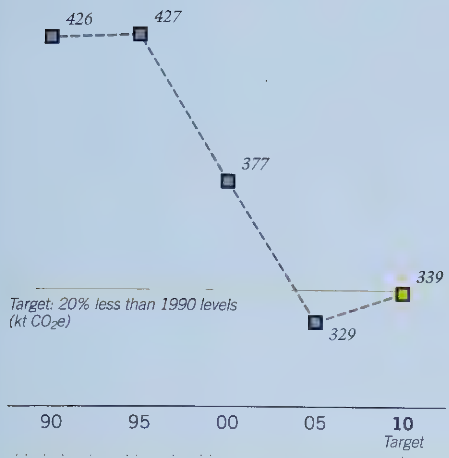
Our Green Energy business will expand further in late 2010 when we bring the 99-MW Talbot Wind Project in Ontario into commercial operation.

All of Enbridge's Green Energy investments feature an attractive, reliable commercial model that is very similar to our traditional businesses. They also build on our excellent track record in environmental stewardship and emissions reductions. These investments add value for our shareholders both

1 *Enbridge System includes Canadian mainline deliveries in western Canada and to the Lakehead System at the United States border as well as Line 8 and Line 9 in eastern Canada.*

2 *Volumes are for the Athabasca mainline and the Waupisoo Pipeline and do not include laterals on the Enbridge Regional Oil Sands System.*

3 *Number of active customers is the number of natural gas-consuming EGD customers at the end of the year.*



Reducing GHG Emissions

Despite a substantial increase in the size and throughput of our operations, we are on track to achieve our goal of a 20% reduction in GHG emissions by 2010. In 2009, Enbridge was recognized for the third consecutive year as a Canadian leader in carbon disclosure by the Conference Board of Canada as part of the international Carbon Disclosure Project.

from a financial and an environmental perspective. While our Green Energy business today is small relative to our liquids and gas businesses, we are committed to its continued growth through capturing new opportunities that meet our investment criteria.

CORPORATE SOCIAL RESPONSIBILITY

Energy delivery is Enbridge's prime corporate responsibility. Energy is essential for humanity, powering every aspect of society. A critical part of our responsibility is delivering energy safely and in an environmentally responsible way. Several years ago, we set a target of reducing the direct greenhouse gas emissions (GHG) of our Canadian operations to 20% below our 1990 levels by 2010. We are already at 23% below our 1990 levels, and that is with a substantial increase in the size and throughput of our operations.

In 2009, we extended our commitment to environmental sustainability by setting a new and ambitious goal: to move toward a neutral environmental footprint for all new projects. We intend to achieve this by conserving an acre for every acre of wilderness we impact, planting a tree for every tree we must remove to build new facilities and generating a kilowatt of renewable power for every kilowatt our new operations consume.

> We recognize that as a leader in business we have a duty to use our expertise and strengths to build stronger communities.

Our success over the past 60 years has been built on not only strong business results, but also our long-standing commitment to being a good neighbour and a fully participating member of the communities in which we operate. We recognize that as a leader in business we have a duty to use our expertise and strengths to build stronger communities. That commitment is shared by our more than 6,000 employees, who are deeply engaged in our growth and sustainability initiatives. We thank all employees for their exemplary work in strengthening Enbridge's reputation and relationships and in striving each and every day to fulfill our responsibility to safely and reliably deliver energy to people.

The Enbridge team was deeply saddened by the death in January 2010 of our colleague Nalvester Maxie in a hydrogen sulfide leak at our gas treating plant near Bryans Mill, Texas. Also, the Company's systems experienced two notable leaks in Canada in 2009 and one in the United States in January 2010. All Enbridge employees strive for zero safety incidents and work hard every day to minimize the Company's environmental impact, and these incidents heighten our resolve to meet those commitments.

EXECUTIVE MANAGEMENT TEAM *(left to right)*

Al Monaco *Executive Vice President, Major Projects & Green Energy*

Patrick D. Daniel *President & Chief Executive Officer*

J. Richard Bird *Executive Vice President, Chief Financial Officer & Corporate Development*

David T. Robottom *Executive Vice President, Corporate Law*

Bonnie D. DuPont *Group Vice President, Corporate Resources*

Stephen J.J. Letwin *Executive Vice President, Gas Transportation & International*

Stephen J. Wuori *Executive Vice President, Liquids Pipelines*

MANAGEMENT AND BOARD CHANGES

We want to express special thanks to Bonnie DuPont, Group Vice President, Corporate Resources, who retires from Enbridge in March 2010. Bonnie has made a huge contribution to the management of Enbridge over the past decade. We wish Bonnie well in her retirement.

Enbridge's value proposition... highly reliable financial performance even during difficult financial times.

In July 2009, the Board of Directors announced the appointment of Charles W. Fischer, former President and Chief Executive Officer of Nexen Inc., to the Board. We are delighted to welcome an individual of Charlie's reputation and expertise. With more than 30 years' experience in the energy industry and a strong personal commitment to community involvement, Charlie is a great leader and one who will make a significant contribution to the Board and the future direction of the Company.

IN CONCLUSION

We believe Enbridge's value proposition is unique and compelling—sustained visible growth and steady income, coupled with highly reliable financial performance even during difficult economic times.

As Enbridge continues to grow, our shareholders will benefit from a superior investment opportunity, today and well into the future.

David A. Arledge
Chair of the Board of Directors

Patrick D. Daniel
President and Chief Executive Officer

March 3, 2010

CORPORATE GOVERNANCE

At Enbridge, corporate governance means that a comprehensive system of stewardship and accountability is in place and functioning among Directors, management and employees of the Company.

Enbridge is committed to the principles of good governance, and the Company employs a variety of policies, programs and practices to manage corporate governance and ensure compliance.

The Board of Directors is responsible for the overall stewardship of Enbridge and, in discharging that responsibility, reviews, approves and provides guidance with respect to the strategic plan of the Company and monitors implementation.

The Board approves all significant decisions that affect the Company and reviews the results. The Board also oversees identification of the Company's principal risks on an annual basis, monitors risk management programs, reviews succession planning and seeks assurance that internal control systems and management information systems are in place and operating effectively.

BOARD OF DIRECTORS *(left to right)*

Dan C. Tutcher *Corporate Director*
Houston, Texas

Catherine L. Williams *Corporate Director*
Calgary, Alberta

J. Herb England *Chairman & Chief Executive Officer, Stahlman-England Irrigation Inc.*
Naples, Florida

J. Lorne Braithwaite *Corporate Director*
Thornhill, Ontario

Charles W. Fisher *Corporate Director*
Calgary, Alberta

James J. Blanchard *Senior Partner, DLA Piper U.S., LLP*
Beverly Hills, Michigan

David A. Arledge *Chair of the Board, Enbridge Inc.*
Naples, Florida

David A. Leslie *Corporate Director*
Toronto, Ontario

George K. Petty *Corporate Director*
San Luis Obispo, California

Patrick D. Daniel *President & Chief Executive Officer, Enbridge Inc.*
Calgary, Alberta

Charles E. Shultz *Chair & Chief Executive Officer, Dauntless Energy Inc.*
Calgary, Alberta

Additional information about Enbridge's corporate governance, Board of Directors and senior management team can be found in the Corporate Governance section of Enbridge's website, www.enbridge.com.

Corporate Social Responsibility You can read more about Enbridge's initiatives in our annual Corporate Social Responsibility Report at *www.enbridge.com/csr2009.*

WE'RE BUILDING MORE THAN PIPELINES

"We believe that to be a good corporate citizen, we have a responsibility to give back to the communities that contribute to our business success. Investing in these communities helps sustain them as vibrant and healthy places to live and work–which, in turn, sustains us as a healthy company."

Patrick D. Daniel
President & CEO, Enbridge Inc.

Enbridge's School Plus program helped Randelle Pete of the Little Pine First Nation and her grade 11 classmates from Sākewew High School in North Battleford, Saskatchewan, participate in a field trip to study the aquatic and terrestrial ecology of nearby Finlayson Island. To date, the School Plus Program has benefited children from kindergarten to high school in 42 First Nations schools.

where SUSTAINABILITY *meets* COMMUNITY

Enbridge is in the business of delivering energy to communities throughout North America, and we believe we have an obligation to do so in a responsible and sustainable way.

Carbon management strategy

Enbridge has already exceeded its target of reducing direct greenhouse gas emissions of Canadian operations to 20% below 1990 levels by 2010. By 2008, we had achieved a 23% reduction. We are in the process of developing a more comprehensive Carbon Management Strategy that will include further actions to reduce the Company's own direct emissions. We also have comprehensive energy-efficiency programs in place that help our natural gas distribution customers use energy more efficiently.

Looking ahead to a future where society makes greater use of renewable energy sources, we are investing in green energy technologies, including wind power, fuel cells, waste-heat recovery and solar. We are also participating in the emerging technology of carbon dioxide (CO_2) capture, pipelining and sequestration.

Stakeholder engagement and consultation

Enbridge is building an unprecedented number of projects in North America.

To ensure specific concerns are identified and understood, we engage stakeholders (e.g., landowners) and communities (e.g., Aboriginal communities) early in the project planning. This enables us to adjust our plans as appropriate and resolve remaining concerns, where possible. Communication with stakeholders continues through regulatory review to construction and into operations.

Enbridge aims to meet or exceed regulatory requirements regarding public consultation. For example, for the Enbridge Northern Gateway Project we established community advisory boards to guide the design, construction and operation of the proposed project. We have also implemented an Aboriginal and Native American Policy that encourages partnerships, program sponsorships, employment opportunities and other capacity-building efforts.

Community partnerships and investment

For communities to be sustainable, they must have solid infrastructure and programming in four areas: Education, Health & Safety, Culture & Community and the Environment. Enbridge also believes that the time, effort and investments it makes in communities contribute to maintaining our social licence to operate. We launched three flagship programs in 2009:

Safe Community

This program supports first response emergency organizations in communities near Enbridge's rights-of-way.

Natural Legacy

Enbridge is committed to environmental stewardship and habitat remediation and conservation, and this program focuses on planting and maintaining native trees and plants in urban and rural areas along Enbridge's rights-of-way.

School Plus

Established in partnership with the Assembly of First Nations, School Plus supports enriched programming and extracurricular activities in First Nations schools near major Enbridge pipeline routes and the Ontario Wind Power Project.

Supply In both Canada and the United States, producers are developing vast new oil and gas resources and there is an increasing demand for renewable energy.

Demand North American industry and consumers alike are seeking secure and reliable sources of energy supply to support economic growth.

Shale Gas: Abundant deposits in both Canada and the United States make unconventional and shale gas major new sources of natural gas supply.

Oil Sands: This is the second largest resource play in the world, with an estimated 170 billion barrels of proven recoverable reserves.

Bakken: This region, which straddles the Canada-U.S. border, is estimated to contain five billion barrels of technically recoverable oil.

Renewables: More governments in North America are focusing on green energy initiatives as society transitions to greater use of renewables.

Gulf of Mexico: This prolific oil and natural gas region is one of the largest sources of supply to the U.S. market.

ENBRIDGE IS LEADING THE WAY

Name any of North America's major energy resource development opportunities–the oil sands, the Bakken Formation, shale gas, Gulf of Mexico deepwater, renewable sources–and Enbridge is there, positioned to deliver energy to key North American markets.

Projects completed in 2009
Southern Access Pipeline (Phase 2)
Spearhead Pipeline Expansion
Line 4 Extension
Hardisty Terminal Expansion
Ontario Wind Power
Sarnia Solar Energy (Phase 1)
Light Sour Pipeline (LSr Pipeline)
Commercially secured growth projects
Alberta Clipper Expansion (2010)
Southern Lights Pipeline (2010)
Saskatchewan and North Dakota systems expansions (Bakken) (2010)
Sarnia Solar Energy (60-MW expansion) (2010)
Talbot Wind Energy (2010)
Christina Lake (oil sands) (2011)
Leismer Project Contract (oil sands) (2011)
Woodland Pipeline (oil sands) (2012)
Walker Ridge Gas Gathering System (Gulf of Mexico) (2014)
Big Foot Oil Pipeline (Gulf of Mexico) (2014)
Fort Hills Pipeline (oil sands) (TBD)

Enbridge is the largest pipeline operator in Canada's oil sands region, a leading pipeline operator in North America's shale gas regions, the dominant pipeline company in the Bakken region, a leader in renewable energy production and the largest operator in the deepwater Gulf of Mexico.

On any single day, Enbridge is the single largest conduit of oil into the U.S., exporting 71% of western Canadian crude oil, and satisfying 12% of the U.S.'s crude oil import needs.

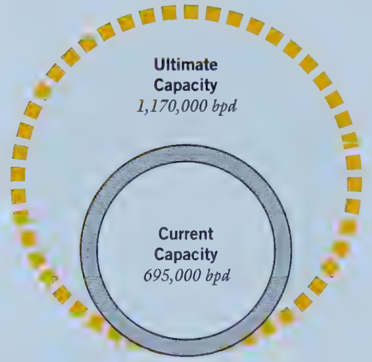
Canada's oil sands

The opportunity

With about 174 billion barrels of combined conventional and oil sands established reserves, Canada ranks second only to Saudi Arabia in global oil reserves.

Of that total, 170 billion barrels are concentrated in Alberta's oil sands deposits, making them the largest resource play in the world.

Today, the oil sands produce over one million barrels of oil per day, and it is estimated that by 2020, production will grow to about four million barrels.



Enbridge's Regional Oil Sands System Both our Athabasca and Waupisoo pipelines are designed for low-cost expansion from their current combined capacity of 695,000 bpd to 1,170,000 bpd—ready for oil sands growth.

Enbridge is there

Enbridge is the largest pipeline operator in the oil sands region.

Our 345,000-barrels-per-day (bpd) Athabasca Pipeline, which runs through the heart of the oil sands to Hardisty, currently has four oil sands projects connected to it and has an ultimate design capacity of 570,000 bpd with the addition of new pump stations.

Our 350,000-bpd Waupisoo Pipeline, which went into service in 2008, connects three new oil sands projects to refineries and upgraders at Edmonton. It is expandable to 600,000 bpd by adding pump stations.

We're growing

Enbridge is actively pursuing many significant growth opportunities to connect new oil sands production through expansion of our existing systems and the construction of new pipelines.

We are building on our very strong competitive position in the region, which stems from our proven track record for on-time, on-budget development and the economies of scale of being the largest operator.

Rapid growth

Enbridge Gas Distribution is Canada's largest gas distribution utility and one of the fastest growing in North America. Enbridge Gas Distribution serves approximately 1.9 million customers in central and eastern Ontario and parts of northern New York State.

In 2009, Enbridge Gas Distribution added about 32,000 new customers. We continue to improve the return on this business under Incentive Regulation, enhancing shareholder value while at the same time enabling us to provide significant savings to our customers in the form of reduced charges for gas delivery.

The Bakken Formation

The opportunity

Producers are driving significant oil and gas production growth in the Bakken Formation, which spans parts of Saskatchewan, Manitoba, North Dakota and Montana and is estimated to contain five billion barrels of technically recoverable oil.

Enbridge is there

Enbridge is strengthening our clear competitive advantage in the Bakken region with growth projects on both sides of the Canada-U.S. border.

We are already the dominant pipeline company in the region through our two sponsored investments—Enbridge Income Fund and Enbridge Energy Partners, L.P.

The Bakken also contains natural gas and natural gas liquids (NGLs), presenting another growth opportunity for the Alliance Pipeline and Aux Sable NGL plant.

Beyond 2010

Looking ahead, we see a tremendous long-term opportunity to build on our existing infrastructure and presence in the Bakken, both in liquids and natural gas, and we are actively working on additional projects for both the Canadian and U.S. sections of this basin.

Shale gas

The opportunity

Shale gas (an emerging form of unconventional gas) is of growing importance to North American energy supply and by the end of this decade could account for over 30% of natural gas production in Canada and the Lower 48 combined.

There are abundant shale gas deposits already under development in northeastern British Columbia (Montney and Horn River plays), Saskatchewan and North Dakota (the Bakken Formation), south-central U.S. (Barnett Shale, Fayette, Eagle Ford and Haynesville plays) and the northeastern U.S. (Marcellus Shale).

Enbridge is there

Enbridge is already strongly positioned in the top quartile of pipeline operators in the major shale gas plays in the Lower 48. Enbridge Energy Partners' gas assets are located in three of the most prolific gas-producing regions in the southeastern U.S. and right next door to the Haynesville Formation, and currently transport, gather and process over three billion cubic feet per day.

The Alliance Pipeline is ideally located right in the heart of the Montney shale gas play in northeastern British Columbia and the Bakken Formation in Saskatchewan and North Dakota.

Offshore expertise

In 2009, Enbridge secured two major offshore projects in the ultra deepwater Gulf of Mexico. The Walker Ridge Gas Gathering Project will be constructed over 306 kilometres (190 miles) and at depths up to 2,130 metres (7,000 feet) and the Big Foot Oil Pipeline at depths up to 1,800 metres (5,900 feet) over 64 kilometres (40 miles). Delivering such projects requires strong technical skills, world-class contractors and exceptional project management capabilities. Enbridge has a strong team with an established track record in the Gulf Coast. Those attributes, combined with our extensive infrastructure, position us well to capture opportunities from new oil and natural gas finds in the region.

Gulf of Mexico ultra deepwater

The opportunity

The Gulf of Mexico is a prolific oil and natural gas region and one of the largest sources of supply to the U.S. market.

The ultra deepwater areas—those with water depths of 1,520 metres (5,000 feet) and over—have very large reservoirs, and despite recent commodity price declines, large producers are continuing to explore the ultra deepwater Gulf. The U.S. Department of the Interior recently forecast that oil production in the Gulf of Mexico will increase substantially over the next several years, possibly reaching 1.8 million bpd.

New Discoveries Gas and oil production is expected to grow based on the discovery of large new reservoirs in the ultra deepwater Gulf of Mexico. Enbridge has the existing infrastructure and the technical capabilities required to capture these new growth opportunities.

Enbridge is there

Enbridge has the best positioning of any provider in the deepwater Gulf of Mexico.

Enbridge serves a majority of the strategically located deepwater host platforms, and our extensive presence in the region positions us well to capture new opportunities both in gas gathering and crude oil.

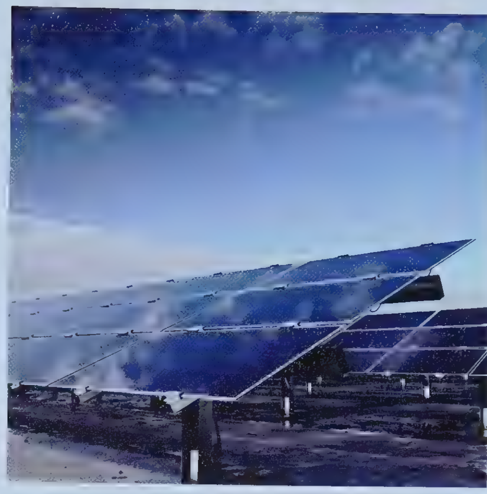
Enbridge offshore pipelines currently transport about 50% of all deepwater Gulf of Mexico natural gas production and include joint-venture interests in 13 transmission and gathering pipelines in five major pipeline corridors in Louisiana, Mississippi and Alabama offshore waters of the Gulf of Mexico.

Our growth projects

In 2009, Enbridge announced two new projects for the Gulf of Mexico ultra deepwater—the Walker Ridge Gas Gathering System and the Big Foot Oil Pipeline—both of which are structured to strengthen returns and align more closely to the reliable business model of Enbridge's traditional businesses.

Innovative solar technology

The photovoltaic technology in use at Enbridge's Sarnia Solar Project generates electricity with no air emissions, no waste production and no water use. When expanded to 80 MW by the end of 2010, the Sarnia Solar Project will be one of the largest photovoltaic solar facilities in North America, and Enbridge expects it will generate enough power to meet the needs of over 12,800 homes and help to save the equivalent of approximately 39,000 tonnes of CO_2 per year.



Green energy

The opportunity

The public's focus on conservation and climate change continues to motivate governments to increase their emphasis on energy efficiency and green energy initiatives, including wind, water, biomass, biogas, solar, waste heat, fuel cell and geothermal energy generation.

Enbridge is there

Enbridge has been a leader in green energy generation for almost a decade, and we plan to keep it that way for many decades to come as society transitions to a greater use of renewable energy.

Solar: Enbridge entered solar energy in a significant way in 2009 with its investment in the 80-MW Sarnia Solar facility. Enbridge believes that solar energy represents meaningful opportunities for long-term growth.

Wind: We currently have wind farms in Alberta, Saskatchewan and Ontario with a combined capacity of over 260 MW, and in 2009 added the 99-MW Talbot Wind Project, expected to begin operations by the end of 2010. We expect future wind opportunities to come through expanding our existing operations and developing new greenfield projects near Enbridge operations throughout North America.

Fuel cell: In 2008, Enbridge launched the world's first hybrid fuel cell power plant that harvests energy that would otherwise be wasted at gas utility pressure reduction stations. The fuel cell produces about 2.2 MW of near zero-emissions electricity—enough to serve about 1,700 homes. We plan to replicate the plant throughout our distribution network in Ontario and market the hybrid fuel cell to other natural gas utility companies in North America.

Waste heat: Enbridge Income Fund has a 50% interest in NRGreen, which generates electricity using waste heat from four of Alliance Canada's compressor stations, generating a total of about 20 MW that is sold under long-term contract to Saskatchewan's grid.

Wind Power **The 190-MW Enbridge Ontario Wind Power Project went into full commercial operation in the first quarter of 2009.**

FINANCIAL RESULTS

Management's Discussion and Analysis

Consolidated Financial Statements

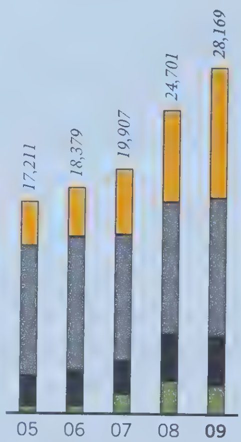
Notes to the Consolidated Financial Statements

MANAGEMENT'S DISCUSSION AND ANALYSIS

This Management's Discussion and Analysis (MD&A) dated February 18, 2010 should be read in conjunction with the audited consolidated financial statements and notes thereto of Enbridge Inc. (Enbridge or the Company) for the year ended December 31, 2009, which are prepared in accordance with Canadian generally accepted accounting principles (GAAP). All financial measures presented in this MD&A are expressed in Canadian dollars, unless otherwise indicated. Additional information related to the Company, including its Annual Information Form, is available on SEDAR at www.sedar.com.

Overview

Enbridge is a North American leader in delivering energy. As a transporter of energy, Enbridge operates, in Canada and the United States, the world's longest crude oil and liquids transportation system. The Company also has a significant involvement in the natural gas transmission and midstream businesses. As a distributor of energy, Enbridge owns and operates Canada's largest natural gas distribution company and provides distribution services in Ontario, Quebec, New Brunswick and New York State. As a clean energy generator, Enbridge is expanding its interests in renewable and green energy technologies, including wind and solar energy, and hybrid fuel cells. Enbridge employs approximately 6,000 people, primarily in Canada and the United States.



Total Assets
(millions of Canadian dollars)

The Company's activities are carried out through four business segments, Liquids Pipelines, Natural Gas Delivery and Services, Sponsored Investments and Corporate, as discussed below.

LIQUIDS PIPELINES

Liquids Pipelines includes the operation and construction of the Enbridge crude oil mainline system and feeder pipelines that transport crude oil and other liquid hydrocarbons. Liquids Pipelines consists of crude oil, natural gas liquids (NGLs) and refined products pipelines and terminals in Canada and the United States.

NATURAL GAS DELIVERY AND SERVICES

Natural Gas Delivery and Services consists of natural gas utility operations, investments in natural gas pipelines, the Company's commodity marketing businesses and international activities.

The core of the Company's natural gas utility operations is Enbridge Gas Distribution Inc. (EGD) which serves residential, commercial, industrial and transportation customers, primarily in central and eastern Ontario as well as northern New York State. This business segment also includes natural gas distribution activities in Quebec and New Brunswick.

Investments in natural gas pipelines include the Company's interests in the United States portion of Alliance Pipeline (Alliance Pipeline US), Vector Pipeline and transmission and gathering pipelines in the Gulf of Mexico.

This segment also includes the Company's investment in Aux Sable, a natural gas fractionation and extraction business.

The commodity marketing businesses manage the Company's volume commitments on Alliance and Vector Pipelines, as well as perform commodity storage, transport and supply management services, as principal and agent.

SPONSORED INVESTMENTS

Sponsored Investments includes the Company's 27% ownership interest in Enbridge Energy Partners, L.P. (EEP), Enbridge's funding of 66.7% of the United States segment of the Alberta Clipper Project through EEP and Enbridge Energy, L.P. (EELP) and a 72% economic interest (41.9% voting interest) in Enbridge Income Fund (EIF). Enbridge manages the day-to-day operations and develops and assesses opportunities for each of these investments, including both organic growth and acquisition opportunities.

EEP transports crude oil and other liquid hydrocarbons through common carrier and feeder pipelines and transports, gathers, processes and markets natural gas and NGLs. EIF is a publicly traded income fund whose primary operations include a crude oil and liquids pipeline and gathering system, a 50% interest in the Canadian portion of Alliance Pipeline (Alliance Pipeline Canada) and partial interests in several green energy investments.

CORPORATE

Corporate consists of new business development activities and investing as well as financing activities, including general corporate investments and financing costs not allocated to the business segments. Corporate also includes the Company's investments in green energy projects.

Performance Overview

	Three Months Ended December 31,		Year Ended December 31,		
	2009	2008	**2009**	2008	2007
(millions of Canadian dollars, except per share amounts)					
Earnings Applicable to Common Shareholders					
Liquids Pipelines	**141**	102	**445**	328	287
Natural Gas Delivery and Services	**96**	143	**635**	958	344
Sponsored Investments	**38**	32	**141**	111	97
Corporate	**25**	(13)	**334**	(76)	(28)
	300	264	**1,555**	1,321	700
Earnings per Common Share	**0.81**	0.72	**4.27**	3.67	1.97
Diluted Earnings per Common Share	**0.80**	0.71	**4.25**	3.64	1.95
Adjusted Earnings [1]					
Liquids Pipelines	**141**	106	**454**	332	286
Natural Gas Delivery and Services	**84**	90	**289**	302	324
Sponsored Investments	**39**	27	**151**	101	86
Corporate	**(25)**	(21)	**(39)**	(58)	(59)
	239	202	**855**	677	637
Adjusted Earnings per Common Share [1]	**0.64**	0.55	**2.35**	1.88	1.79
Cash Flow Data					
Cash provided by operating activities	**182**	431	**2,017**	1,372	1,362
Cash used in investing activities	**(1,162)**	(2,091)	**(3,306)**	(2,853)	(2,229)
Cash provided by financing activities	**912**	1,930	**1,109**	1,840	904
Dividends					
Common Share Dividends Declared	**139**	123	**555**	489	453
Dividends Per Common Share	**0.37**	0.33	**1.48**	1.32	1.23
Revenues					
Commodity Sales	**2,491**	3,116	**9,720**	13,432	9,536
Transportation and other services	**696**	808	**2,746**	2,699	2,383
	3,187	3,924	**12,466**	16,131	11,919
Total Assets	**28,169**	24,701	**28,169**	24,701	19,907
Total Long-Term Liabilities	**16,392**	13,179	**16,392**	13,179	10,467

1 *Adjusted earnings and adjusted earnings per common share are non-GAAP measures that do not have any standardized meaning prescribed by GAAP. For more information on non-GAAP measures see pages 36 and 102.*

EARNINGS APPLICABLE TO COMMON SHAREHOLDERS

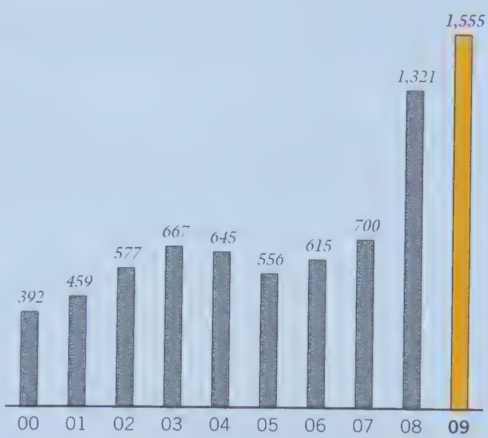
Earnings applicable to common shareholders for the three months ended December 31, 2009 were $300 million, or $0.81 per common share, an increase of $36 million compared with $264 million, or $0.72 per common share, for the three months ended December 31, 2008. The increase primarily resulted from allowance for equity funds used during construction (AEDC) in Liquids Pipelines and EELP, within Sponsored Investments, as well as a higher contribution from EEP, also within Sponsored Investments. Other factors contributing to the increase include favourable tax rate changes and net unrealized fair value gains on derivative financial instruments used to risk manage foreign exchange variability. These earnings increases were partially offset by decreased earnings from Aux Sable due to unrealized derivative fair value losses of $25 million recognized in the fourth quarter of 2009 compared with similar gains of $35 million recognized in the fourth quarter 2008.

Earnings applicable to common shareholders were $1,555 million for the year ended December 31, 2009, or $4.27 per common share, compared with $1,321 million, or $3.67 per common share, for the year ended December 31, 2008. Included in earnings for the year ended December 31, 2009 was a $329 million gain related to the sale of the Company's investment in Oleoducto Central S.A. (OCENSA) and a $25 million gain related to the sale of NetThruPut (NTP). Earnings for the year ended December 31, 2008 included a gain of $556 million related to the sale of the Company's investment in Compañía Logística de Hidrocarburos CLH, S.A. (CLH). Excluding the impact of these dispositions, earnings for the year ended December 31, 2009 were $436 million higher than for the year ended December 31, 2008. The increase in earnings resulted from similar factors as for the three months results as well as unrealized foreign exchange gains on the translation of foreign-denominated intercompany loans.

Earnings applicable to common shareholders were $1,321 million for the year ended December 31, 2008, compared with $700 million for the year ended December 31, 2007. The increase in earnings resulted from AEDC in Liquids Pipelines, a higher contribution from EGD and unrealized fair value gains on derivative financial instruments in Aux Sable, Energy Services and Corporate, partially offset by decreased earnings from International as the Company sold its interest in CLH in the second quarter of 2008. Earnings for the year ended December 31, 2008 also reflected a $556 million gain on the sale of CLH, partially offset by the recognition of a $32 million income tax charge as a result of an unfavourable court decision related to previously owned United States pipeline assets.

ADJUSTED EARNINGS

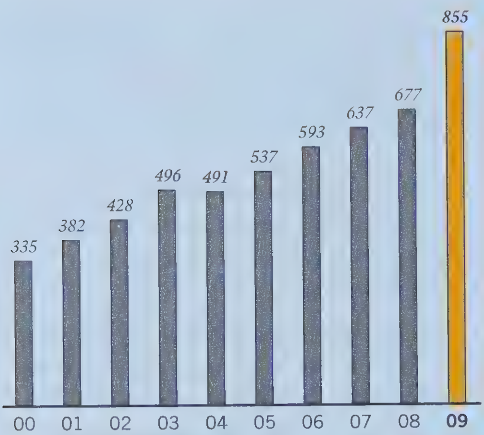
Adjusted earnings were $239 million, or $0.64 per common share, for the three months ended December 31, 2009, compared with $202 million, or $0.55 per common share, for the months ended December 31, 2008. Adjusted earnings were $855 million, or $2.35 per common share, for the year ended December 31, 2009, compared with $677 million, or $1.88 per common share, for the year ended December 31, 2008.



Earnings Applicable to Common Shareholders
(millions of Canadian dollars)

The increase in adjusted earnings for both the fourth quarter and full year primarily resulted from increased contributions from a number of the Company's assets as follows:

- AEDC on both Alberta Clipper (within Enbridge System and EELP) and Southern Lights Pipeline.
- An increased contribution from EEP resulting from additional assets placed in service and related tariff surcharges for recent expansions, the Company's increased ownership interest and a more favourable exchange rate.
- Increased adjusted earnings from Enbridge Offshore Pipelines (Offshore) due to higher volumes and a more favourable exchange rate.
- Increased adjusted earnings from Energy Services due to higher volumes and the impact of realizing favourable storage and transportation margins.



Adjusted Earnings
(millions of Canadian dollars)

These increases were partially offset by decreased earnings from International as a result of the sale of OCENSA in the first quarter of 2009 and CLH in the second quarter of 2008.

Adjusted earnings for the year ended December 31, 2008 were $677 million, or $1.88 per common share, compared with $637 million, or $1.79 per common share, for the year ended December 31, 2007. The $40 million, or $0.09 per common share, increase was primarily a result of:

- New facilities within Liquids Pipelines as well as AEDC on Southern Lights Pipeline and, within Enbridge System, on both Southern Access Mainline Expansion and Alberta Clipper Project.
- Increased Aux Sable adjusted earnings due to strong fractionation margins.
- Higher incentive income and increased earnings at EEP primarily due to higher gas and crude oil delivery volumes, tariff surcharges for recent expansions and a greater ownership interest following an additional subscription of Class A units in December 2008.
- Improved earnings in Energy Services resulting from market conditions which enabled higher margins to be captured on storage and transportation contracts as well as increased transportation and storage volumes.

These significant operating factors that increased 2008 adjusted earnings were partially offset by decreased earnings from International as a result of the sale of CLH in the second quarter of 2008 and lost revenue from Offshore as a result of Hurricanes Gustav and Ike.

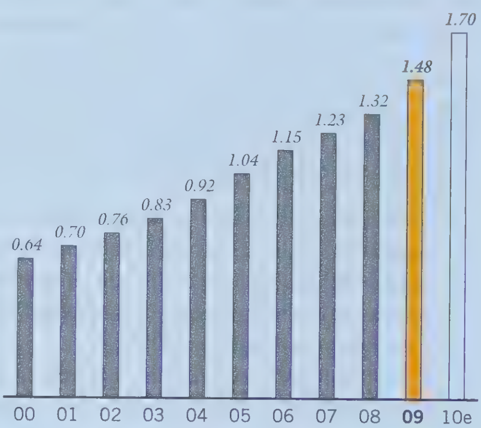
CASH FLOWS

The Company increased cash generated by operating activities each year from 2007 through 2009 on the success of its growth projects and strong operating results, culminating with cash provided by operating activities of $2,017 million for the year ended December 31, 2009. Operating cash flow, together with cash provided by financing activities and proceeds from the sale of an international investment in 2009, funded the Company's ongoing growth initiatives in 2009, including capital expenditures of $3,225 million.

For the three months ended December 31, 2009, cash provided by operating and financing activities of $182 million and $912 million, respectively, funded investing activities of $1,162 million, which consisted primarily of capital expenditures. The decline in additions to property, plant and equipment in the fourth quarter of 2009 compared with the fourth quarter of 2008 reflects the completion of several, substantial construction projects that were under development in 2008, including Southern Access Mainline Expansion, Line 4 Extension, Spearhead Pipeline Expansion and Hardisty Terminal projects.

DIVIDENDS

The Company has paid, and consistently increased, common share dividends since its public inception in 1953. Based on estimated 2010 dividends, the annual rate of increase has averaged 10.3% since 2000 and 10.0% since inception. In December 2009, the Company announced a 15% increase in its quarterly dividend to $0.425 per common share, or $1.70 annualized, effective March 1, 2010. The Company's dividend payout policy and ratio reflects a strong and stable long-term outlook for its business. The Company continues to target a pay out of approximately 60% to 70% of adjusted earnings as dividends and, with the most recent dividend increase, the 2010 pay out is expected to be near the midpoint of the range. In 2009, dividends paid per share were 63% of adjusted earnings per share (2008–70%, 2007–69%).



Dividends per Common Share
(Canadian dollars per share)

The following chart shows dividends per share for the last 10 years, as well as estimated dividends for 2010, based on the quarterly dividend of $0.425 per common share declared by the Board of Directors on December 3, 2009.

REVENUES

The Company generates revenue from two primary sources: commodity sales, and transportation and other services.

Commodity sales revenue is earned through the Company's natural gas distribution and energy marketing activities and is subject to fluctuations in commodity prices. While revenues generated by the natural gas distribution business vary with the price of natural gas, earnings remain neutral due to the pass through nature of these costs. Similarly, the impact of commodity prices on revenues derived from the Company's energy marketing activities do not directly impact earnings since commodity prices also affect input costs associated with such activities. Commodity sales revenue for the year ended December 31, 2009 totaled $9,720 million compared with $13,432 million for the year ended December 31, 2008 and $9,536 for the year ended December 31, 2007. Commodity sales revenue totaled $2,491 million in the fourth quarter of 2009, a 20% decline from the fourth quarter of 2008. Similar trends were experienced in commodity costs over these same periods. The period-over-period variances are primarily driven by natural gas and crude oil commodity prices, both of which increased notably in 2008 over 2007, only to experience subsequent declines in 2009 amidst global economic uncertainty.

Transportation and other services includes revenues derived from the Company's liquids transportation and natural gas transmission services, renewable energy generation and related services. Transportation and other services revenue for the year ended December 31, 2009 totaled $2,746 million compared with revenues of $2,699 million for the year ended December 31, 2008. Main contributors to this variance include:

- Increased contributions from Liquids Pipelines growth projects that entered service in 2009, including the Line 4 Extension, Spearhead Expansion, LSr Pipeline (constructed in conjunction with the Southern Lights Pipeline Project) and Hardisty Terminal projects.
- Full year contributions from Waupisoo Pipeline and Ontario Wind Project that entered service at various stages throughout 2008.
- Completion of the Shenzi Lateral project within Offshore in April 2009.
- Unfavourable variances in realized and unrealized gains and losses on derivative instruments used to manage natural gas processing margins in Aux Sable.

Transportation and other services revenue for the three months ended December 31, 2009 was $696 million compared with $808 million for the corresponding period of 2008. The decline is primarily due to variances in realized and unrealized gains and losses on derivative instruments used to manage natural gas processing margins in Aux Sable.

For the year ended December 31, 2008, transportation and other services revenue increased 13% to $2,699 million compared with $2,383 million in 2007. Segment highlights include:

- Revenues in the Liquids Pipelines segment increased due to higher base tolls on Enbridge System and the new Waupisoo Pipeline included in the Enbridge Regional Oil Sands System.
- Natural Gas Delivery and Services transportation revenue included higher Alliance Pipeline US tolls, the impact of Vector Pipeline expansion and revenues from Neptune within Offshore.
- EIF revenue, within Sponsored Investments, increased due to higher tolls at Alliance Pipeline Canada and higher allowance oil revenue from the Saskatchewan System.

FORWARD-LOOKING INFORMATION

Forward-looking information, or forward-looking statements, have been included in this MD&A to provide the Company's shareholders and potential investors with information about the Company and its subsidiaries, including management's assessment of Enbridge's and its subsidiaries' future plans and operations. This information may not be appropriate for other purposes. Forward-looking statements are typically identified by words such as "anticipate", "expect", "project", "estimate", "forecast", "plan", "intend", "target", "believe" and similar words suggesting future outcomes or statements regarding an outlook. Forward-looking information or statements included or incorporated by reference in this document include, but are not limited to, statements with respect to: expected earnings or adjusted earnings; expected earnings or adjusted earnings per share; expected costs related to projects under construction; expected in-service dates for projects under construction; expected capital expenditures; and estimated future dividends.

Although Enbridge believes that these forward-looking statements are reasonable based on the information available on the date such statements are made and processes used to prepare the information, such statements are not guarantees of future performance and readers are cautioned against placing undue reliance on forward-looking statements. By their nature, these statements involve a variety of assumptions, known and unknown risks and uncertainties and other factors, which may cause actual results, levels of activity and achievements to differ materially from those expressed or implied by such statements. Material assumptions include assumptions about: the expected supply and demand for crude oil, natural gas and natural gas liquids; prices of crude oil, natural gas and natural gas liquids; expected exchange rates; inflation; interest rates; the availability and price of labour and pipeline construction materials; operational reliability; customer project approvals; maintenance of support and regulatory approvals for the Company's projects; anticipated in-service dates; and weather. Assumptions regarding the expected supply and demand of crude oil, natural gas and natural gas liquids, and the prices of these commodities, are material to and underlay all forward-looking statements. These factors are relevant to all forward-looking statements as they may impact current and future levels of demand for the Company's services. Similarly, exchange rates, inflation and interest rates impact the economies and business environments in which the Company operates, may impact levels of demand for the Company's services and cost of inputs, and are therefore inherent in all forward-looking statements. Due to the interdependencies and correlation of these macroeconomic factors, the impact of any one assumption on a forward-looking statement cannot be determined with certainty, particularly with respect to expected earnings or adjusted earnings and associated per share amounts, or estimated future dividends. The most relevant assumptions associated with forward-looking statements on projects under construction, including estimated in-service dates, and expected capital expenditures include: the availability and price of labour and pipeline construction materials; the effects of inflation and foreign exchange rates on labour and material costs; the effects of interest rates on borrowing costs; and the impact of weather and customer and regulatory approvals on construction schedules.

Enbridge's forward-looking statements are subject to risks and uncertainties pertaining to operating performance, regulatory parameters, project approval and support, weather, economic and competitive conditions, exchange rates, interest rates, commodity prices and supply and demand for commodities, including but not limited to those risks and uncertainties discussed in this MD&A and in the Company's other filings with Canadian and United States securities regulators. The impact of any one risk, uncertainty or factor on a particular forward-looking statement is not determinable with certainty as these are interdependent and Enbridge's future course of action depends on management's assessment of all information available at the relevant time. Except to the extent required by law, Enbridge assumes no obligation to publicly update or revise any forward-looking statements made in this MD&A or otherwise, whether as a result of new information, future events or otherwise. All subsequent forward looking statements, whether written or oral, attributable to Enbridge or persons acting on the Company's behalf, are expressly qualified in their entirety by these cautionary statements.

NON-GAAP MEASURES

This MD&A contains references to adjusted earnings/(loss), which represent earnings or loss applicable to common shareholders adjusted for non-recurring or non-operating factors on both a consolidated and segmented basis. These factors are reconciled and discussed in the financial results sections for the affected business segments. Management believes that the presentation of adjusted earnings/(loss) provides useful information to investors and shareholders as it provides increased transparency and predictive value. Management uses adjusted earnings/(loss) to set targets, assess performance of the Company and set the Company's dividend payout target. Adjusted earnings/(loss) and adjusted earnings/(loss) for each of the segments are not measures that have a standardized meaning prescribed by Canadian GAAP and are not considered GAAP measures; therefore, these measures may not be comparable with similar measures presented by other issuers. See *Non-GAAP Reconciliations* section for a reconciliation of the GAAP and non-GAAP measures.

Corporate Vision and Key Objective

Enbridge's vision is to be the leading energy delivery company in North America. While the Company may be viewed as having achieved elements of this vision, enhancing and sustaining this position remains a continuing, long-term pursuit. The Company's objective is to generate superior economic value for shareholders through investing capital in a low-risk and disciplined manner. Consistently applied, such stewardship could continue to generate attractive risk adjusted returns and in turn, provide for consistent and growing dividend distributions and related capital appreciation.

Corporate Strategy

In support of its long-term vision, the Company employs several key strategies that guide decision making across the enterprise. The Company's strategies focus on:

- leveraging the strategic location of its existing asset base;
- developing new platforms for growth and diversification;
- focusing on execution and operating excellence;
- maintaining financial strength and flexibility; and
- development of people, safety and environmental stewardship and corporate social responsibility.

Enbridge's strategy is reviewed annually with direction from its Board of Directors. The Company continually assesses ways to generate value for shareholders, including reviewing opportunities that may lead to acquisitions, dispositions or other strategic transactions, some of which may be material. Opportunities are screened, analyzed and must meet operating, strategic and financial benchmarks before being pursued.

STRENGTHENING OUR CORE BUSINESS

The Company has an established history of serving the North American transportation needs of key crude oil and natural gas markets. The Company is focused on adding value for customers and improving customers' profitability. This focus has aligned the Company with its customers and relevant supply and demand fundamentals and has consistently formed a basis for the Company's strategy. However, evolving supply and demand fundamentals and growing competition are serving to create new opportunities and challenges within the Company's core businesses. Amid this changing business environment, the Company is strengthening its core business position and aggressively pursuing new opportunities to expand and extend its current asset base.

Extending the reach of the current asset base is a multi-faceted objective. Key strategies within the Liquids Pipelines segment include regional pipeline development, gathering system and storage infrastructure expansion and new market access. Regional pipeline development primarily includes projects which connect new oil sands lease production to existing hubs upstream of the Canadian mainline. The commercial agreement and ongoing development activity related to the Woodland Pipeline represents a recent success in realizing this objective. The Company is working with several other oil sands customers in developing further transportation options for other projects in the oil sands region of northern Alberta. The Company is also expanding its gathering systems in Saskatchewan and North Dakota which are strategically located to capture increased production from the Bakken play. As transportation needs grow so too do terminal and storage infrastructure requirements throughout the network, and the Company's strategy will seek opportunities to provide additional capacity in the Fort McMurray and Hardisty, Alberta regions as well as in the Cushing, Oklahoma area. The Company continues to pursue opportunities to provide its customers broader market access for Canadian bitumen and synthetic crudes and provide new sources of supply for refiners. These efforts include leveraging existing pipeline networks into additional United States markets as well as developing the proposed Northern Gateway pipeline to provide access to markets off the Pacific Coast of Canada.

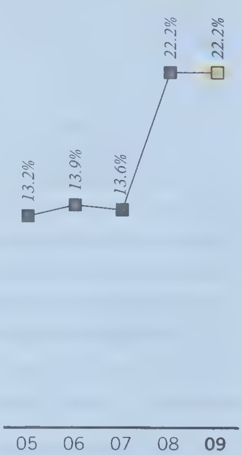
The fundamentals of the natural gas market in North America have been significantly altered in recent years with the emergence of unconventional shale gas plays. The Company's natural gas strategy includes expanding its footprint in these emerging areas. Alliance Pipeline is well positioned to service the Montney play in northeast British Columbia and is currently evaluating opportunities to expand its service offerings in that area. Growth in the Haynesville shale in northwest Louisiana will lend additional support to the Company's proposed LaCrosse Pipeline. In addition to these onshore strategies, the Company continues to pursue and win natural gas gathering expansion opportunities for ultra-deep projects in the Gulf of Mexico which improve the risk and return profile of its investment in this area.

DEVELOPING NEW PLATFORMS FOR GROWTH AND DIVERSIFICATION

The development of new platforms to diversify and sustain long-term growth is an important strategy for Enbridge. Renewable energy is a significant source of potential new growth as government initiatives and changing social beliefs are creating new opportunities to deliver green energy solutions with risk and return characteristics consistent with Enbridge's low-risk business model. Renewable energy projects can deliver stable cash flows and attractive returns though the use of long-term power purchase agreements and fixed price engineering, procurement and construction contracts. Renewable energy is also an important part of Enbridge's corporate social responsibility strategies, particularly with respect to greenhouse gases (GHG) and the environment. Business development efforts in renewable energy are focused primarily on clean power projects, including wind, solar, waste heat recovery and fuel cell initiatives.

Similar to renewable energy, carbon dioxide (CO_2) capture and sequestration not only supports Enbridge's social investment strategy but also represents a potentially significant investment opportunity, should the technology prove viable.

The Company's Pathfinding group will also continue to explore other longer-term energy technologies and facilitate innovations to assist its customers and sustain its favourable position.



Return on Average Shareholders' Equity
(percentage)

FOCUSING ON EXECUTION AND OPERATIONS

Effective project execution and management of operations is a critical component of Enbridge's strategic plan. Operational excellence is particularly critical in an environment where customers have become increasingly cost conscious, competition in the Company's core business has intensified and environmental stewardship has heightened.

Successful execution of the existing slate of commercially secured projects is a significant driver of Enbridge's near-term earnings and cash flow growth, and, therefore, a strategic priority. Project execution is a core competency at Enbridge and the Company continues to build upon its project management skills and processes, primarily through the Major Projects support team which was established in early 2008. Major Projects now manages projects above $50 million for all liquids, natural gas and renewable projects and continues to deliver projects on time and on budget. Major Projects focuses on success factors such as cost estimation, regulatory permitting, material and labour sourcing and project governance. This competency is highly valued and represents another Enbridge strength when competing for new business.

Cost efficiency and operating performance is becoming an increasing driver of value in a deregulated world with increased competition. Under the incentive programs in place in certain of the Company's business units, rates and tolls, as well as the Company's earnings, depend on cost and operating performance. Returns in the Company's natural gas gathering and processing business are also directly impacted by operating costs. Key initiatives within the business units to manage costs include: upgrading management information and reporting systems; rigorous cost tracking performance against relevant benchmarks; and implementing best practice procurement strategies and enhanced "change management" processes to ensure anticipated savings are realized from new programs.

Superior service, safety and reliability are integral to Enbridge's customer value proposition. As always, cost management initiatives are balanced with the safe and reliable operation of the Company's system and the need to ensure ongoing customer satisfaction. Throughout the organization, the Company is placing increased emphasis on understanding customers and their decision processes, and on regular measurement and management of service quality.

With respect to safety, Enbridge strives to employ the best available practices and technologies for integrity management, systems maintenance and operations in order to mitigate risks to the public, our employees and the environment.

PRESERVING FINANCIAL STRENGTH AND FLEXIBILITY

Disciplined capital management is a fundamental and company differentiating characteristic. As an asset-intensive business, Enbridge creates value for its investors through maximizing the spread between its return on invested capital and its cost of funds. Enbridge's financial strategies ensure the Company has sufficient liquidity to meet its capital requirements. To support this objective, the Company develops financing plans and strategies to maintain and improve Enbridge's credit ratings, diversify its funding sources and maintain ready access to capital markets in both Canada and the United States.

A key tenet of the Company's low-risk business model is mitigation of exposure to certain market price risks. As a result, the Company has developed a robust risk management process which ensures earnings volatility from manageable risk remains contained within the Company's approved guideline of 5% of adjusted earnings. Enbridge will continue to proactively hedge interest rate, foreign exchange and commodity price exposures. As well, the continued management of counterparty credit risk remains an ongoing priority.

ENVIRONMENTAL STEWARDSHIP AND CORPORATE SOCIAL RESPONSIBILITY

Enbridge has strong corporate social responsibility practices. Enbridge defines corporate social responsibility as conducting business in a socially responsible way, protecting the environment and the health and safety of people, supporting human rights and engaging, respecting and supporting the communities and cultures with which the Company works. Enbridge's complete 2009 Corporate Social Responsibility Report can be found at www.enbridge.com/csr2009. None of the information contained on, or connected to, the Enbridge website is incorporated or otherwise part of this MD&A.

In 2009, the Company launched an enterprise-wide goal of achieving a neutral environmental footprint by 2015. The goal consists of three key commitments:

- we will conserve an acre of natural or wilderness land for every acre we permanently impact from the construction of new facilities;
- we will plant a tree for every tree we remove to build new facilities; and
- we will generate a kilowatt of renewable power, through our investments in renewable and alternative energy, for each kilowatt of power consumed by our operations.

To achieve its neutral footprint goal, Enbridge will work with nature conservancies in Canada and the United States to help purchase natural wilderness lands throughout North America. The land that Enbridge conserves will be similar to the areas that have been affected. The Company has also begun to plant trees. To mark the Company's 60th anniversary, Enbridge planted more than 60,000 trees in 60 communities along its rights of way in Canada and the United States.

Enbridge's community investments are also noteworthy. The Company launched three major community investment initiatives in 2009. School Plus, in partnership with the Assembly of First Nations, provides financial support to enrichment programming and extracurricular activities in First Nations schools near major Enbridge rights-of-way; the Safe Community program serves to confirm the priority Enbridge places on health and safety in our right-of-way communities, by directly and visibly supporting those right-of-way organizations who would respond to an emergency on one or more of our lines or at one of our facilities; and the Natural Legacy program focuses on tree planting and specific environmental initiatives in communities in proximity to our major rights-of-way.

To complement community investments in its Canadian and United States operating areas, Enbridge will also exercise leadership in extending the benefits of energy availability to underdeveloped countries. In 2009, Enbridge launched the energy4everyone Foundation, which has applied to the Canadian Revenue Agency for charitable status, with a vision of empowering people and communities to improve their own lives by providing energy to everyone. The Foundation aims to leverage the expertise and resources of the Canadian energy industry to affect significant enhancement in quality of life through the delivery and deployment of affordable, reliable and sustainable energy services and technologies to communities in need around the world.

Canadian Crude Oil Production

(thousands of barrels per day)

Sources: National Energy Board (2007–2009), Canadian Association of Petroleum Producers (2010).

Industry Fundamentals

SUPPLY AND DEMAND FOR LIQUIDS

North American liquids infrastructure fundamentals remain favourable for the foreseeable future. The United States continues to be reliant on imported crude oil to satisfy its needs. Western Canada has surpassed both Mexico and Saudi Arabia to become the largest crude oil exporter to the United States. Canada's oil sands, one of the largest oil reserves in the world, are becoming an increasingly prominent source of supply. Combined conventional and oil sands established reserves of approximately 174 billion barrels compare with Saudi Arabia's proved reserves of approximately 260 billion barrels. The National Energy Board (NEB) estimates that total Western Canadian Sedimentary Basin (WCSB) production averaged approximately 2.5 million barrels per day (bpd) in 2009 (2008–2.4 million bpd; 2007–2.4 million bpd). Other sources of supply growth include deepwater Gulf of Mexico, which is also distant from market, and some of the shale plays like the Bakken in the midcontinent.

In connection with the global economic downturn, crude oil price weakness and volatility caused some crude oil producers to defer projects that were planned to commence over the next decade. More recently, improved macroeconomic conditions, higher oil prices and reduced development costs have spurred a number of oil sands projects to be revisited and sanctioned; however, a tempered rate of growth is expected in the near term relative to prior forecasts. The Canadian Association of Petroleum Producers' (CAPP) June 2009 growth case estimates indicate that future WCSB production is expected to steadily increase to more than 3.6 million bpd by 2019. This forecasted growth of 1.1 million bpd is attributed to increased oil sands production in Alberta.

While global demand for crude oil is expected to resume its growth trajectory given the strength in emerging regions, North American demand for crude oil in the next few years is expected to remain relatively flat. Inventories of crude oil and refined product remain very high as influenced by the recent economic downturn and the emergence of biofuels. Refining economics have materially weakened over this period, contributing to the recent announcements of a variety of marginal refinery closures. Most of these closures are in regions that are not served by Enbridge infrastructure. Other more profitable refineries are growing and have reconfiguration projects under construction. Some of these refineries currently process Canadian crude and some are preparing to. Accordingly, there remain meaningful growth opportunities for Canadian crude oil into existing and new markets in the United States.

With the expected increase in heavy oil production in western Canada, there is an increasing requirement for condensate (or similar light commodity) to be used as a blending agent in order to transport these high viscosity volumes to market. Condensate is a light hydrocarbon which is conventionally a bi-product of natural gas production or NGLs fractionation. Production of this commodity is decreasing in western Canada but with the demand for diluents from heavy oil producers, there has been an increasing need to import. Currently, volumes are transported via rail to Alberta from the United States as well as from international sources via tankers and rail from the West Coast. In mid-2010, Enbridge's Southern Lights condensate pipeline will be in service bringing incremental volumes of condensate from the United States to Alberta to meet producer's needs.

SUPPLY AND DEMAND FOR NATURAL GAS

Over the course of the last year the North American gas industry has evolved meaningfully. Shale gas is proving to be an enormous and wide spread resource that may alter continental gas flow directions. With robust supplies of shale gas located in the lower 48 United States, it may not be necessary to import large quantities of liquefied natural gas (LNG) into North America as previously envisioned, and pipelines to access northern gas may be deferred for many years. Growth expectations for shale gas are so strong that the industry's greatest challenge now has transitioned to how to sustain development by extending market demand.

North American Natural Gas Production
(billions of cubic feet per day)
Sources: Energy Information Administration (United States), National Energy Board (Canada), Enbridge research.

Since the 1990s, production in the Rocky Mountain region of the United States, primarily from tight shale gas, has more than doubled to approximately 9 billion cubic feet per day (bcf/d). This amount of growth will likely repeat over the next 12 to 15 years. Established shale plays in the Midcontinent region such as the Barnett, Fayetteville and Woodford, along with emerging plays such as Haynesville in northwest Louisiana and Marcellus in Appalachia, have now become the continental gas development hotspots. After seeing a decline in drilling rig activity in some of these plays in the summer of 2009, activity in these regions has increased in recent months with the prospect of higher future prices. This increased drilling could contribute significantly to supply in 2010, extending the natural gas price weakness seen in 2009.

Additional shale plays exist throughout North America, such as the Horn River and Montney in British Columbia and Utica shale in Quebec. Shale plays located closer to populated markets, such as the Marcellus, are particularly notable in that they require limited infrastructure to access premium prices. If market area shale gas proves to be extensive, it may have a significant impact on the long haul transport business, displacing supplies from distant basins and offloading associated pipelines. On the other hand, opportunities abound for gathering, processing and short haul connectivity.

North American natural gas demand contracted in 2009 as a direct impact of the recession. Industrial demand weakened the most while low gas prices led to gas for coal substitution in power generation, supporting gas demand in that sector. Following the anticipated economic recovery, natural gas demand is expected to grow in all sectors but gas-fired generation may lead the group as natural gas is expected to be a preferred fuel in an increasingly carbon-conscious marketplace. While gas fired generation growth will occur, it will be restricted for the next several years as coal projects already under construction enter service and more renewable power projects come on line.

Even with an economic recovery, growth in unconventional gas supply is expected to be limited by growth in demand, resulting in North American prices remaining lower relative to recent years. This lower price level should be further supported by the relatively lower, and increasingly so, cost of developing shale gas supply. With a lower cost structure, North American gas is likely on a divergent path with oil, which should help support strong fractionation spreads.

Global LNG production is ramping up with several projects under construction. In the near term, LNG supply from these new projects will be seeking markets during a global recession. North American markets may be susceptible to dumping of LNG for short periods, impacting gas prices, at least until global economies recover.

Overall, abundant low cost gas supplies are anticipated to be positive news for North American gas markets and are likely to lead to renewed interest in natural gas as an economically priced, clean burning fuel.

Growth Projects

Enbridge is in the midst of its largest capital program in the Company's 60 year history. During 2008 and 2009, the Company has completed more than $4.5 billion of new growth projects and has $7 billion of additional commercially secured projects scheduled to come into service in 2010 and 2011, with a further $5 billion secured for post-2011 in service. In addition, the Company has a further $30 billion in growth opportunities under development, but not yet commercially secured, for the post-2011 period, of which it expects to be successful on a significant portion.

The following table summarizes commercially secured projects, within each of the Company's business segments, which were recently completed, or are currently under active development or construction. These growth projects contribute to anticipated annual earnings per share growth rates expected to average 10% through 2013, with the inventory of projects under development expected to sustain this growth rate into the second half of the decade.

(in billions of Canadian dollars, unless stated otherwise)	Actual/Estimated Capital Cost [1]	Expenditures to Date	Actual/Expected In-Service Date	Status
LIQUIDS PIPELINES				
1. Southern Access Mainline Expansion–Canadian portion	$0.2 billion	$0.2 billion	2008	Complete
2. Spearhead Pipeline Expansion	US$0.1 billion	US$0.1 billion	2009	Complete
3. Line 4 Extension	$0.3 billion	$0.3 billion	2009	Complete
4. Hardisty Contract Terminal	$0.6 billion	$0.6 billion	2009	Complete
5. Alberta Clipper–Canadian portion	$2.3 billion	$2.1 billion	2010	Mechanically complete
6. Southern Lights Pipeline	$0.5 billion + US$1.7 billion	$0.5 billion + US$1.4 billion	Light Sour Line–2009; Diluent Line–2010	Under construction
7. Woodland Pipeline–Phase I	$0.5 billion	No significant expenditures to date	2012	Regulatory and pre-construction
8. Fort Hills Pipeline System	~$2.0 billion	$0.1 billion	TBD	Commercially secured; pending customer timing
NATURAL GAS DELIVERY AND SERVICES				
9. Shenzi Lateral	US$0.1 billion	US$0.1 billion	2009	Complete
10. Walker Ridge Gas Gathering System	US$0.5 billion	No significant expenditures to date	2014	Pre-construction
11. Big Foot Oil Pipeline	US$0.3 billion	No significant expenditures to date	2014	Pre-construction
SPONSORED INVESTMENTS				
12. EEP–Southern Access Mainline Expansion–United States portion	US$2.1 billion	US$2.1 billion	2009	Complete
13. EEP–North Dakota System Expansion	US$0.2 billion	US$0.1 billion	2010	Complete
14. EEP/EELP–Alberta Clipper–United States portion	US$1.3 billion	US$0.9 billion	2010	Under construction
15. EIF–Saskatchewan System Capacity Expansion	$0.1 billion	No significant expenditures to date	2010	Under construction
CORPORATE				
16. Ontario Wind Project	$0.5 billion	$0.5 billion	2009	Complete
17. Talbot Wind Energy Farm	$0.3 billion	$0.1 billion	2010	Under construction
18. Sarnia Solar Project	$0.4 billion	$0.1 billion	2010	Under construction

1 *These amounts are actual costs or current estimates and subject to upward or downward adjustment based on various factors.*

Risks related to the development and completion of growth projects are described under *Risk Management*.

COMMERCIALLY SECURED PROJECTS

△ Liquids Pipelines

1 Southern Access Mainline Expansion–Canadian portion
2 Spearhead Pipeline Expansion
3 Line 4 Extension
4 Hardisty Contract Terminal
5 Alberta Clipper–Canadian portion
6 Southern Lights Pipeline
7 Woodland Pipeline–Phase I
8 Fort Hills Pipeline System

▲ Natural Gas Delivery and Services

9 Shenzi Lateral
10 Walker Ridge Gas Gathering System
11 Big Foot Oil Pipeline

○ Sponsored Investments

12 EEP–Southern Access Mainline Expansion–U.S. portion
13 EEP–North Dakota System Expansion
14 EEP–Alberta Clipper–U.S. portion
15 EIF–Saskatchewan System Capacity Expansion

□ Corporate

16 Ontario Wind Project
17 Talbot Wind Energy Farm
18 Sarnia Solar Project

— Current Assets
Growth Opportunities

LIQUIDS PIPELINES

Southern Access Mainline Expansion Project

The Southern Access Mainline Expansion Project is complete, with only some restoration work remaining. It has added a total of 400,000 bpd incremental capacity to the mainline system. Construction of the second and final stage of the United States expansion project, which consisted of a new 224-kilometre (139-mile), 42-inch pipeline from Delavan, Wisconsin to Flanagan, Illinois, was completed on schedule in the first quarter of 2009. The pipeline was placed into service and the associated toll surcharge took effect on April 1, 2009. In Canada, upgrades at 18 pump stations to improve pumping effectiveness were completed in early 2009. The Company started collecting associated tolls in April 2008 on stage 1 facilities placed in-service.

The total cost of the project decreased to approximately US$2.3 billion (Enbridge – $0.2 billion, EEP – US$2.1 billion). The estimated capital cost for the Canadian portion was revised from $0.3 billion to $0.2 billion based on refinements to the scope of the project, agreed to with CAPP, to reflect the subsequent approval of the Alberta Clipper Project.

The Southern Access Expansion Project is an expansion of the mainline system. The cost of the project is recovered through tolls in Canada and the United States. A toll surcharge mechanism has been negotiated with shippers and approved by regulators to recover the costs of this expansion including a return on and of the capital investment. The recovery of costs and returns is independent of throughput.

Spearhead Pipeline Expansion

This US$0.1 billion expansion includes additional pumping stations to increase capacity from Flanagan, Illinois to Cushing, Oklahoma by 68,300 bpd to 193,300 bpd. The expansion began in September 2008 and was placed in service on May 1, 2009.

Sale of Spearhead North Pipeline

On May 1, 2009, the Company sold a section of the Spearhead Pipeline to EEP for proceeds of US$75 million. The section of the crude oil pipeline system sold, known as Spearhead North, includes approximately seven storage tanks and 121 kilometres (75 miles) of pipeline that was reversed to provide northbound service from Flanagan, Illinois to Griffith, Indiana. Spearhead North complements EEP's existing Lakehead System interconnectivity at Flanagan, which is the terminus of the Southern Access Expansion.

Line 4 Extension Project

The $0.3 billion Line 4 Extension Project was substantially complete and ready to receive linefill at the end of March 2009, and associated tolls were collected starting April 1, 2009. Final restoration work was completed in the summer of 2009. The project expanded capacity from Edmonton to Hardisty by 880,600 bpd. Similar to the Southern Access and Alberta Clipper projects, the Line 4 project costs are recovered through surcharges on mainline tolls.

Hardisty Contract Terminal

Enbridge has completed its crude oil contract terminal at Hardisty, Alberta, adding tankage capacity of 7.5 million barrels. With all 19 new tanks in service, the $0.6 billion Hardisty Contract Terminal is one of the largest crude oil terminals in North America. Remaining seasonal and restoration work is expected to be completed in early 2010.

Alberta Clipper Project

The Alberta Clipper Project involves the construction of a new 36-inch diameter pipeline from Hardisty, Alberta to Superior, Wisconsin generally within or alongside EEP's existing rights-of-way in the United States and Enbridge's existing rights-of-way in Canada. The Alberta Clipper Project will interconnect with the existing mainline system in Superior where it will provide access to Enbridge's full range of delivery points and storage options, including Chicago, Toledo, Sarnia, Patoka and Cushing. The project will have an initial capacity of 450,000 bpd, is expandable to 800,000 bpd and will form part of the existing

Enbridge System in Canada and the EEP Lakehead System in the United States. The Alberta Clipper Project is a full cost of service agreement with a return of 225 basis points (bps) over the NEB multi pipeline rate of return.

Construction on the Canadian segment of the line was mechanically completed in December 2009, and remains on schedule for an expected in-service date of April 1, 2010. This segment has an estimated cost of $2.3 billion, including allowance for funds used during construction (AFUDC), with expenditures to date totaling $2.1 billion. As of January 2010, construction is approximately 90% complete on the United States segment and it also remains on schedule to be ready for service by April 1, 2010. The cost of the United States segment is estimated at US$1.3 billion, with expenditures to date totaling US$0.9 billion. As announced in July 2009, Enbridge has committed to fund 66.7% of the United States segment of the Alberta Clipper Project through EELP. Similar to the Southern Access Project, the costs of the Alberta Clipper Project are recovered through surcharges on mainline tolls in both Canada and the United States.

For both the Canadian and United States segments of the Alberta Clipper Project, tariffs will be filed with the appropriate regulators to be effective on April 1, 2010, the date the project is expected to be ready for service. The tariff for the United States segment, and its effective date, will be filed on the basis of the Alberta Clipper US Term Sheet, despite a petition filed in January 2010 by a shipper requesting the Federal Energy Regulatory Commission (FERC) to delay the tariff. Following that petition filing, several shippers filed interventions requesting to be part of the process. The Alberta Clipper US Term Sheet was approved by CAPP on June 28, 2007 and by the FERC on August 28, 2008. We have reviewed and will respond to the shipper petition, which we believe to be without merit.

Southern Lights Pipeline

When completed, in the second half of 2010, the 180,000 bpd Southern Lights Pipeline will transport diluent from Chicago, Illinois to Edmonton, Alberta. The project involves reversing the flow of a portion of Enbridge's Line 13, an existing crude oil pipeline which runs from Edmonton to Clearbrook, Minnesota. In order to replace the light crude capacity that would be lost through the reversal of Line 13, the Southern Lights Project also includes the construction of a new 20-inch diameter light sour crude oil pipeline (LSr Pipeline) from Cromer, Manitoba to Clearbrook, and modifications to existing Line 2. These changes to the existing crude oil system increased southbound light crude system capacity by approximately 45,000 bpd. The capacity replacement will permit Line 13 to be taken out of service and reversed for diluent service. The LSr Pipeline and Line 2 modifications, which allow Line 2 to operate at higher design rates, were completed and placed in service in the first quarter of 2009.

In the United States, construction of the LSr Pipeline and Line 2 modifications, as well as diluent pipeline construction between Superior, Wisconsin and Streator, Illinois, are complete. Remaining mainline construction includes approximately 305 kilometers (190 miles) of diluent segment, in conjunction with construction of the Alberta Clipper Project, between Clearbrook, Minnesota and Superior, Wisconsin. Construction of this remaining United States line segment commenced in the third quarter of 2009 and was 80% complete at year end. In addition, construction has commenced on diluent receipt tankage at Manhattan as well as pump station facilities along the newly constructed diluent line in the United States.

The total expected project cost is US$1.7 billion for the United States segment and $0.5 billion for the Canadian segment. Expenditures to date are US$1.4 billion and $0.5 billion for the United States and Canadian segments, respectively. Southern Lights is a contract pipeline backed by shippers with strong credit ratings.

Line 13 Exchange

In February 2009, the Company transferred the United States section of the newly constructed LSr Pipeline to EEP at book value in exchange for the United States portion of Line 13. The exchange was made on a basis considered to be fair to both parties and the tolls and earnings on the LSr Pipeline and Line 13 within EEP are expected to be substantially unchanged.

Woodland Pipeline

In June 2009, Enbridge entered into an agreement with Imperial Oil Resources Ventures Limited (Imperial Oil) and ExxonMobil Canada Properties (ExxonMobil) to provide for the transportation of blended bitumen from the Kearl oil sands mine to crude oil hubs in the Edmonton, Alberta area. The project will be phased with the mine expansion, with the first phase involving construction of a new 36-inch diameter pipeline from the mine to the Cheecham Terminal, and service on Enbridge's existing Waupisoo Pipeline from Cheecham to the Edmonton area. The new pipeline, to be called the Woodland Pipeline, will be extended from Cheecham to Edmonton in conjunction with the second phase of the Kearl project. The Woodland Pipeline is being undertaken as a joint venture between Enbridge, Imperial Oil and ExxonMobil. Enbridge filed regulatory applications for Phase I facilities at the end of 2009 and expects the pipeline will come into service in late 2012. The total estimated cost of the pipeline from the mine to the Cheecham Terminal and related facilities is $0.5 billion, but is subject to finalization based on scope, detailed engineering and regulatory approvals.

Fort Hills Pipeline System

In November 2007, Enbridge was selected by Fort Hills Energy L.P. (FHELP) as its pipeline and terminaling services provider for the initial phase of the Fort Hills project and all subsequent expansions. In late 2008, FHELP announced that its final investment decision for the mining portion of the project was being deferred until costs could be reduced, and commodity prices and financial markets strengthened. It also announced that the Fort Hills upgrader was put on hold and that a decision to proceed with the upgrader would be made at a later date. Accordingly, the scope of the Fort Hills Pipeline System is being reevaluated by FHELP and the planned in-service date for the project has been deferred beyond the original planned date of mid-2011. FHELP has until June 2011 to give notice to Enbridge to proceed with the pipeline. Expenditures to date are approximately $0.1 billion and are commercially recoverable from FHELP.

Northern Gateway Project

The Northern Gateway Project, which is being commercially pursued, involves constructing a twin pipeline system from near Edmonton, Alberta, to a new marine terminal in Kitimat, British Columbia. One pipeline would transport crude oil for export from the Edmonton area to Kitimat, and is expected to be a 36-inch diameter line with an initial capacity of 525,000 bpd. The other pipeline would be used to import condensate and is expected to be a 20-inch diameter line with an initial capacity of 193,000 bpd.

The Company has secured $100 million funding from Western Canada producers and Pacific Rim refiners toward the costs of seeking the necessary regulatory approvals for the project.

The federal Minister of Environment and the Chairman of the NEB have established a Joint Review Panel (JRP) to consider the Northern Gateway application and make a recommendation to the Canadian federal government on whether the project should be approved and what terms and conditions should be attached to that approval. The JRP will review, among other things, the project's economic, technical and financial feasibility and the environmental and socio-economic impacts of the project. The terms of reference for the JRP were released in December 2009.

Aboriginal consultation and accommodation is a constitutional requirement of the Crown based on established or asserted Aboriginal rights along the pipeline route and tanker waterway. The Canadian Environmental Assessment Agency (CEAA) is responsible for coordinating consultation with Aboriginal groups with respect to the potential impacts of the project on Aboriginal and Treaty rights. CEAA initially consulted with Aboriginal groups on the proposed regulatory process for the project. A number of Aboriginal groups made submission that the proposed consultation process did not meet the Crown's consultation obligations and a separate Aboriginal review process was required for the project. The federal government did not accept these submissions and established the JRP process as the primary mechanism for Aboriginal groups to be consulted on the impacts of the project. The JRP process has no mandate to resolve Aboriginal land claims or issues of Aboriginal rights and title.

The federal government has also issued a project-specific Aboriginal Consultation Framework for Northern Gateway creating a consultation plan for the project. Funding is available from CEAA to assist Aboriginal groups with the costs of participating in the JRP process and a majority of the Aboriginal groups along the corridor have submitted applications for such funding. Nevertheless, it is anticipated that a number of Aboriginal groups will maintain their position that the current process does not meet the Crown's duty to consult.

The project is also undertaking its own comprehensive public consultation program, which includes a series of community open houses and community advisory boards designed to gather input, answer questions and build public awareness and understanding about the project. The Company is committed to working with First Nations and Métis communities along the pipeline route to create opportunities for economic partnerships and to incorporate traditional knowledge into the planning and operations of the proposed project.

Notwithstanding this commitment, certain Aboriginal groups have publicly stated their opposition to the project and have indicated that they are considering all options to prevent the project. These options could include legal challenges to the consultation efforts of the Crown or to the JRP process or its outcomes. The result of such legal challenges would ultimately be decided by the courts, but even if unsuccessful, they could potentially increase the risk of project delay. See *Aboriginal Relations.*

Enbridge expects to file its regulatory application with the NEB in 2010. Subject to continued commercial support, regulatory and other approvals, and adequately addressing Aboriginal groups' concerns, the Company estimates that Northern Gateway could be in-service as early as the 2016 time frame. The NEB posts public filings related to Northern Gateway on its website and Enbridge also maintains a Northern Gateway Project site in addition to information available on www.enbridge.com. None of the information contained on, or connected to, the NEB website, the Gateway Project website or Enbridge's website is incorporated or otherwise part of this MD&A.

NATURAL GAS DELIVERY AND SERVICES

Shenzi Project

Enbridge completed construction of a natural gas lateral to connect the new deepwater Shenzi field to existing Enbridge infrastructure. The US$0.1 billion 18-kilometre (11-mile), 12-inch diameter gas pipeline has capacity of 0.1 bcf/d. The Shenzi lateral, which delivers natural gas through the Company's 22%-owned Cleopatra Pipeline, the 74%-owned Manta Ray Pipeline and the 74%-owned Nautilus Pipeline, was placed into service in April 2009 concurrent with producer first volumes.

Walker Ridge Gas Gathering System

On July 29, 2009, Enbridge announced it had entered into Letters of Intent (LOI) with Chevron Corp. to expand its central Gulf of Mexico offshore pipeline system. Under the terms of the LOI, Enbridge will construct, own and operate the Walker Ridge Gas Gathering System (WRGGS) to provide natural gas gathering services to the proposed Jack, St. Malo and Big Foot ultra-deepwater developments. The WRGGS is expected to include approximately 306 kilometres (190 miles) of 8-inch, 10-inch and/or 12-inch diameter pipeline at depths of up to approximately 2,150 metres (7,000 feet) and will have a capacity of 0.1 bcf/d. The estimated cost of the WRGGS is approximately US$0.5 billion, subject to finalization of scope and definitive cost estimates.

The terms of the LOI ensure a minimum rate of return to Enbridge with no volume risk. If volumes are achieved as expected by the producer, returns would improve from this base level. In addition, Enbridge takes no capital cost risk on the project.

Big Foot Oil Pipeline

On October 5, 2009, Enbridge announced it had entered into a LOI with Chevron USA, Inc., Statoil Gulf of Mexico LLC and Marubeni Oil & Gas (USA) Inc. to construct and operate a 64-kilometre (40-mile) 20-inch oil pipeline from the proposed Big Foot ultra-deepwater development in the Gulf of Mexico. This crude oil pipeline project is complementary to Enbridge's previously announced plans to construct the WRGGS. The estimated cost of the Big Foot Oil Pipeline, which will be located about 274 kilometres (170 miles) south of the coast of Louisiana, is approximately US$0.3 billion and the pipeline is expected to be in-service in 2014 and has the same commercial structure as noted under Walker Ridge Gas Gathering System. Combined with the WRGGS project, the proposed oil pipeline would bring the total Enbridge investment for the projects to US$0.8 billion.

LaCrosse Pipeline

In May 2009, the Company conducted a successful non-binding open season for the proposed LaCrosse Pipeline. This project, which is being commercially pursued, includes an interstate pipeline to transport natural gas from EEP's Carthage Hub in Panola County, Texas, to Washington Parish in Southeastern Louisiana. The 483-kilometre (300-mile) pipeline would have a capacity in excess of 1.0 bcf/d and would provide an outlet for increasing supplies of natural gas originating in the East Texas and Fort Worth producing basins and the growing Haynesville Shale play. The next stage of the project involves confirming customer interest and the expected cost of the new construction.

SPONSORED INVESTMENTS

Enbridge Energy Partners

North Dakota System Expansion

EEP undertook a further expansion of the North Dakota Pipeline System at an approximate cost of US$0.2 billion during 2009. The expansion increased system capacity from 110,000 bpd to 161,000 bpd and consisted of upgrades to existing pump stations, additional tankage as well as infrastructure to facilitate extensive use of drag reducing agents that are injected into the pipeline. The commercial structure for this expansion is a cost-of-service based surcharge that has been added to the existing transportation rates. The related tolling surcharge has been adjusted to include costs of this phase of the expansion that became effective January 1, 2010. Approval for the expansion was received from the FERC in October 2008 and the expansion came into service in early 2010.

Enbridge Income Fund

Saskatchewan System Capacity Expansion

EIF has finalized the scope of Phase II of the Saskatchewan System Capacity Expansion to include three separate projects that will reduce capacity constraints at a variety of locations. Collectively, the projects will increase capacity across the system by approximately 125,000 bpd at an estimated cost of approximately $0.1 billion. Construction commenced during the third quarter of 2009 and all three projects are expected to be complete in the fourth quarter of 2010.

CORPORATE

Ontario Wind Project

The 190-megawatt (MW) Ontario Wind Project, located in the Municipality of Kincardine on the eastern shore of Lake Huron in Ontario, was completed in the fourth quarter of 2008, and 65 of the 115 wind turbines were operating and delivering power to the grid by the end of 2008. During the first quarter of 2009, the remaining 50 turbines were phased into service and the wind project attained full commercial operation. The project has demonstrated near design level operational performance through its net capacity factor and high availability of wind turbines. The final capital cost of the project is $0.5 billion.

Talbot Wind Energy Project

On November 19, 2009, Enbridge announced the development of the 99-MW Talbot Wind Energy Project near Chatham, Ontario with Renewable Energy Systems Canada Inc. (RES Canada). Enbridge will have a 90% interest in the project and an option to acquire the remaining 10% interest. RES Canada will construct the wind project under a fixed price, turnkey, engineering, procurement and construction agreement. The project utilizes 43 Siemens 2.3-MW wind turbines and, under a multi-year fixed price agreement, Siemens will provide operations and maintenance services for the wind turbines. The Talbot Wind Energy Project will deliver energy to the Ontario Power Authority under a Renewable Energy Supply (RES) III 20-year power purchase agreement and is expected to be completed by December 2010 at a capital cost of $0.3 billion.

Sarnia Solar Project

On October 2, 2009, Enbridge announced the development of the 20-MW Sarnia Solar Project with First Solar, Inc. (First Solar). On December 8, 2009, the Company announced a 60-MW expansion of the project. After the completion of the expansion, the project will be the largest photovoltaic, solar energy facility in operation in North America. First Solar, a global leader in solar energy, is constructing the project under a fixed price engineering, procurement and construction contract, utilizing its thin film photovoltaic technology. First Solar will also provide operations and maintenance services under a long-term contract. Power output of the facility will be sold to the Ontario Power Authority under a 20-year power purchase agreement. The initial 20-MW facility attained commercial operation in December 2009 and the 60-MW facility is expected to be in service by December 2010. The expected capital cost of both facilities is $0.4 billion.

Alberta Saline Aquifer Project

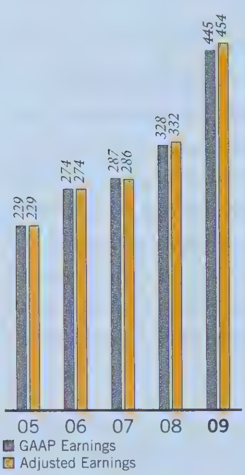
The 38-member Alberta Saline Aquifer Project (ASAP) completed Phase 1 of its three-phase CO_2 storage project in March 2009. This phase focused on identifying saline aquifer locations in Alberta that would be suitable for a CO_2 storage pilot project. The costs associated with this phase were covered by ASAP participants and a grant from the Alberta Energy Research Institute.

ASAP is now working on securing funding and a source of CO_2 such that it can move on to Phase 2 of the project. Phase 2 will involve developing the pilot project, receiving all necessary regulatory approvals and actually injecting CO_2 into the identified aquifers. The Phase 2 pilot project will give the ASAP team the opportunity to test the sequestration technologies and to demonstrate that the technologies are safe and reliable.

Liquids Pipelines

EARNINGS

(millions of Canadian dollars)	2009	2008	2007
Enbridge System	**295**	212	202
Enbridge Regional Oil Sands System	**72**	69	54
Southern Lights Pipeline	**58**	27	7
Spearhead Pipeline	**17**	12	10
Olympic Pipeline	**9**	7	10
Feeder Pipelines and Other	**3**	5	3
Adjusted Earnings	**454**	332	286
Enbridge System – impact of tax changes	**–**	–	1
Enbridge Regional Oil Sands System – Cheecham leak accrual	**(9)**	–	–
Feeder Pipelines and Other – asset impairment loss	**–**	(4)	–
Earnings	**445**	328	287



Liquids Pipelines Earnings
(millions of Canadian dollars)

Liquids Pipelines adjusted earnings were $454 million in 2009 compared with $332 million in 2008. The increase was largely due to higher earnings from Enbridge System and Southern Lights Pipeline, including the impact of AEDC, partially offset by higher operating costs including compensation.

While under construction, certain regulated pipelines are entitled to recognize AEDC in earnings. These amounts will contribute to earnings throughout the Company's significant growth period and will be collected in tolls once the pipelines are in service. The earnings impact of AEDC for the year ended December 31, 2009 was $74 million (2008 – $18 million) for Enbridge System, primarily relating to Alberta Clipper, and $44 million (2008 – $27 million) for Southern Lights Pipeline.

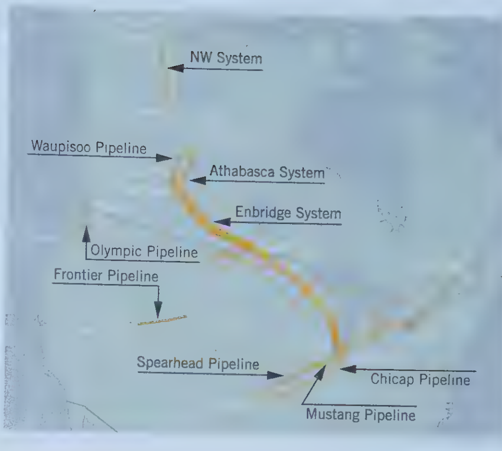
Liquids Pipelines adjusted earnings were $332 million in 2008 compared with $286 million in 2007. The increase was due primarily to strong contributions from the Enbridge and Enbridge Regional Oil Sands Systems, as well as the recognition of AEDC on Enbridge System and Southern Lights Pipeline.

Liquids Pipelines earnings were impacted by the following non-recurring or non-operating adjusting items:

- Enbridge System was affected by favourable tax rate changes in 2007.
- A $9 million after-tax expense resulting from clean up and remediation costs related to a valve leak within the Enbridge Cheecham Terminal on the Enbridge Regional Oil Sands System in January 2009, which is not indicative of the expected future performance of this asset.
- In the fourth quarter of 2008, the Company recorded an impairment loss of $4 million on Manyberries Pipeline, a small feeder pipeline located in Canada.

ENBRIDGE SYSTEM

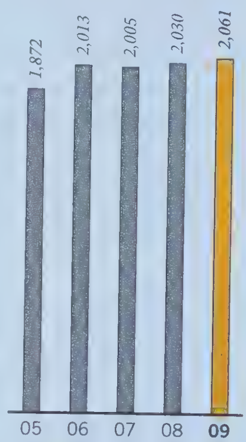
The mainline system is comprised of Enbridge System and Lakehead System (the portion of the mainline in the United States that is operated by Enbridge and owned by EEP). Enbridge has operated, and frequently expanded, the mainline system since 1949. Through six adjacent pipelines with a combined capacity of approximately 2 million bpd, the system transports various grades of crude oil and diluted bitumen from western Canada to the midwest region of the United States and eastern Canada. Also included within the Enbridge System and located in eastern Canada are two crude oil pipelines and one refined products pipeline with a combined capacity of 0.4 million bpd. Average system utilization in 2009 was 80%; however, it is expected to decrease in 2010 due to a combination of additional pipeline capacity being added to the system by the Company and a new pipeline being brought into service by a competitor.



Liquids Pipelines

Incentive Tolling

Tolls on Enbridge System are governed by various agreements, which are subject to the approval of the NEB. The NEB's jurisdiction over the Enbridge System includes statutory authority over matters such as construction, rates and ratemaking agreements and other contractual arrangements with customers. Significant agreements include the incentive tolling settlement (ITS) applicable to the Enbridge mainline system (excluding Line 8 and Line 9), the Terrace agreement, the SEP II Risk Sharing Agreement and the Southern Access Expansion Agreement which is recovered via the Mainline Expansion Toll. Tolls on the core mainline system have been governed by ITS since 1995, with the most recent ITS term effective through 2009. Discussions and negotiations are continuing for an extension to the ITS which will support a competitive toll structure. The Company anticipates that a settlement will be reached in early 2010. In the event that a settlement cannot be reached, the Company could file a cost of service application.



Enbridge System— Average Deliveries

(thousands of barrels per day)

In 2009, the ITS allowed the sharing of earnings in excess of a stipulated threshold and provided a fixed annual mainline integrity allowance. In addition, performance metrics bonuses and penalties aligned the Company's interests with its shippers.

Enbridge achieved total performance metrics bonuses of approximately $13 million for the year ended December 31, 2009, compared with approximately $15 million and $11 million for the years ended December 31, 2008 and 2007, respectively.

In conjunction with the Terrace agreement, the ITS continues the throughput protection provisions included in earlier incentive tolling arrangements, ensuring the Company is insulated from volume fluctuations beyond its control. The agreements govern both current and future shippers on the pipeline and establish tolls each year based on an agreed capacity and an allowed revenue requirement. Where actual volumes on the pipeline fall short of the agreed capacity and Enbridge is unable to fully collect its annual revenue requirement, the deficiency is rolled into the subsequent year's tolls for collection from shippers at that time and a receivable, referred to as the Transportation Revenue Variance (TRV), is recognized.

This basis may affect the timing of recognition of revenues compared with that otherwise expected under Canadian GAAP for companies that are not rate-regulated. As at December 31, 2009, $98 million (2008 – $114 million) was recorded as tolling deferrals.

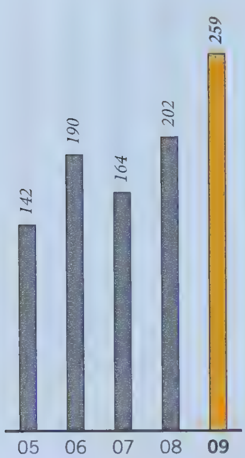
Enbridge pays taxes each year only on the tolls collected in cash; therefore the tax payable on the TRV lags behind the recognition of the revenue. As the Terrace capacity is increasingly utilized, there will be less TRV recorded and more cash tolls collected. This will result in the Company paying taxes in future years on both the prior year's TRV and the current year's cash tolls.

Results of Operations

Enbridge System adjusted earnings were $295 million for the year ended December 31, 2009 compared with $212 million for the year ended December 31, 2008. Enbridge System adjusted earnings increased due to increased tolls from a higher rate base as a result of Line 4 entering service in April 2009, lower financing costs as well as higher AEDC on Alberta Clipper. These positive impacts were partially offset by higher operating costs, including compensation, and costs related to leak remediation.

Enbridge System adjusted earnings were $212 million for the year ended December 31, 2008 compared with $202 million for the year ended December 31, 2007. This increase was due to increased tolls from a higher rate base as a result of Southern Access Mainline Expansion entering service on March 31, 2008 and the AEDC recognized while the project was under construction.

Enbridge System earnings for the year ended December 31, 2007 were impacted by $1 million as a result of favourable tax rate changes.



Enbridge Regional Oil Sands System—Average Deliveries
(thousands of barrels per day)

ENBRIDGE REGIONAL OIL SANDS SYSTEM

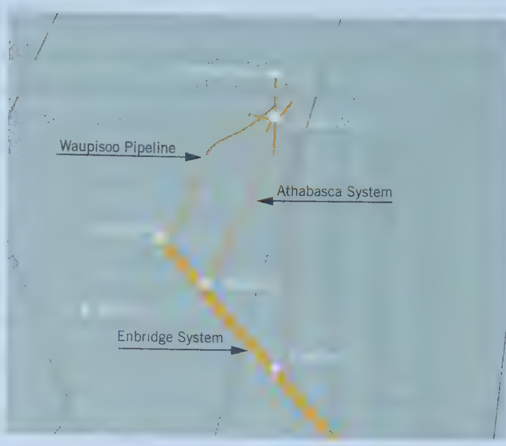
Enbridge Regional Oil Sands System includes two long haul pipelines, the Athabasca Pipeline and the Waupisoo Pipeline, as well as a variety of other facilities including the MacKay River, Christina Lake, Surmont and Long Lake facilities. It also includes the Company's interest in the Hardisty Caverns Limited Partnership, which provides crude oil tankage service; and three large terminals: the Athabasca Terminal located north of Fort McMurray, Alberta, the Cheecham Terminal, which is a new hub located 95 kilometres south of Fort McMurray where the Waupisoo Pipeline initiates, and the Hardisty Contract Terminal, one of the largest crude oil terminals in North America.

The Athabasca Pipeline is a 540-kilometre (335-mile) synthetic and heavy oil pipeline, built in 1999, that links the Athabasca oil sands in the Fort McMurray, Alberta region to a pipeline hub at Hardisty, Alberta. The Athabasca Pipeline has an ultimate design capacity of approximately 570,000 bpd, dependent on viscosity of crude being shipped. It is currently configured to transport approximately 345,000 bpd.

The Company has a long-term (30-year) take-or-pay contract with the major shipper on the Athabasca Pipeline which commenced in 1999. Revenue is recorded based on the contract terms negotiated with the major shipper, rather than the cash tolls collected. The contract provides for volumes and tolls designed to achieve an underpinning return on equity (ROE) based on an assumed debt/equity ratio and level of operating costs. The committed volumes and the tolls specified in the contract do not generate sufficient cash revenues in the early years to compensate Enbridge for the debt and equity returns as well as the cost of providing service. As a result, Enbridge is recording a receivable in these years, which will be collected in tolls in future years. This treatment ensures that the revenue recognized each period is in accordance with the contract.

The Waupisoo Pipeline is a 380-kilometre (236-mile) synthetic and heavy oil pipeline that entered into service on May 31, 2008 and provides access to the Edmonton market for oil sands producers. The Waupisoo Pipeline initiates at Enbridge's Cheecham Terminal and terminates at its Edmonton Mainline Terminal. The pipeline currently has a design capacity, dependent on crude slate, of up to 350,000 bpd, which can ultimately be expanded to 600,000 bpd.

Enbridge has a long-term (25-year) take-or-pay commitment with the four founding shippers on the Waupisoo Pipeline who collectively have contracted for approximately one-third of the initial capacity on the line. The associated revenues provide for a base ROE with significant upside potential as incremental founders and third party volumes are added.



Enbridge Regional Oil Sands System

Results of Operations

Adjusted earnings for the year ended December 31, 2009 were $72 million compared with $69 million for the year ended December 31, 2008 and $54 million for the year ended December 31, 2007. In both the year ended December 31, 2009 and 2008, the increase in Enbridge Regional Oil Sands System adjusted earnings reflected contributions from the Waupisoo Pipeline that entered service in June 2008 and the continued positive impact of terminal infrastructure additions, partially offset by higher operating costs.

Enbridge Regional Oil Sands System earnings for 2009 were impacted by a $9 million after-tax expense resulting from the clean up and remediation costs related to a valve leak within the Enbridge Cheecham Terminal in January 2009, which is not indicative of the expected future performance of this asset.

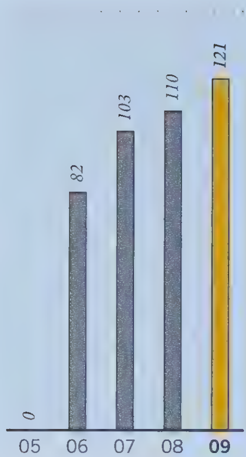
SOUTHERN LIGHTS PIPELINE

This pipeline received regulatory approval in Canada in the first quarter of 2008 and is currently under construction in both the United States and Canada. Upon completion, the 180,000 bpd, 20-inch diameter Southern Lights Pipeline will transport diluent from Chicago, Illinois to Edmonton, Alberta.

Enbridge will receive tariffs under long-term (15-year) contracts with committed shippers. Tariffs provide for recovery of all operating and debt financing costs, plus a ROE at a pre-determined rate. Uncommitted volumes, up to a specified amount, provide for tariff revenues that are fully credited to all shippers. Enbridge retains 25% of uncommitted tariff revenues on volumes above the specified amount, with the remainder being credited to shippers.

Results of Operations

Southern Lights Pipeline earnings for each of 2009, 2008 and 2007 reflected AEDC recognized on a growing capital base while the project continued to be under construction. In 2009, earnings from the new light sour pipeline, which became operational during the first quarter of 2009, were also reflected.



Spearhead Pipeline—
Average Deliveries
(thousands of barrels per day)

SPEARHEAD PIPELINE

Spearhead Pipeline delivers crude oil from Chicago, Illinois to Cushing, Oklahoma. The performance of this pipeline steadily increased and with further support of new committed shippers, the Spearhead Pipeline Expansion was completed in May 2009. This expansion increased the capacity from 125,000 bpd to 193,300 bpd from the new initiating point of Flanagan, Illinois to Cushing.

Initial committed shippers and expansion shippers currently account for more than 70% of the 193,300 bpd capacity on Spearhead. Both the initial committed shippers and expansion shippers were required to enter into 10 year shipping commitments at negotiated rates that were offered during the open season process. The balance of the capacity is currently available to uncommitted shippers on a spot basis at FERC approved rates.

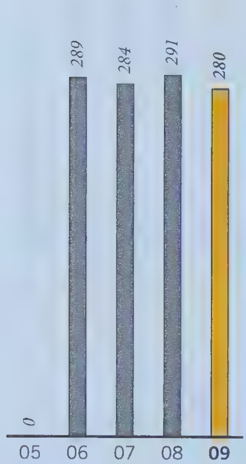
Results of Operations

Spearhead Pipeline earnings increased to $17 million for the year ended December 31, 2009 compared with $12 million for the year ended December 31, 2008 due to increased volumes resulting from the expansion completed in May 2009.

Earnings increased to $12 million for the year ended December 31, 2008 compared with $10 million for the year ended December 31, 2007 as a result of higher throughputs and higher tolls on committed volumes.

OLYMPIC PIPELINE

Enbridge has a 65% interest in the Olympic Pipeline, the largest refined products pipeline in the State of Washington, transporting approximately 290,000 bpd of gasoline, diesel and jet fuel. The pipeline system extends approximately 480 kilometres (300 miles) from Blaine, Washington to Portland, Oregon, connecting four Puget Sound refineries to terminals in Washington and Portland. BP Pipelines (North America) Inc. (BP) is the operator of the pipeline.



Olympic Pipeline—
Average Deliveries
(thousands of barrels per day)

Results of Operations

Olympic Pipeline earnings were $9 million, $7 million and $10 million for the years ended December 31, 2009, 2008 and 2007, respectively. Olympic's cost of service tolling methodology requires annual toll adjustments for over or under collection of the cost of service in prior years. Olympic Pipeline earnings for both the years ended December 31, 2009 and 2008 reflected lower average tolls effective July 1 in each of those years to compensate for over collection in the previous year. Earnings for the year ended December 31, 2009 also reflected lower operating and administrative costs, which resulted in increased earnings in 2009, while earnings for the year ended December 31, 2008 also reflected an increase in pipeline integrity costs.

FEEDER PIPELINES AND OTHER

Feeder Pipelines and Other primarily includes the NW System, which transports crude oil from Norman Wells in the Northwest Territories to Zama, Alberta; interests in a number of liquids pipelines in the United States; contract tankage facilities; and business development costs related to Liquids Pipelines activities.

Results of Operations

Adjusted earnings for Feeder Pipelines and Other were $3 million in 2009 compared with $5 million in 2008 and $3 million in 2007. In 2009, adjusted earnings were impacted by increased business development costs.

Earnings for the year ended December 31, 2008 were impacted by an impairment loss of $4 million on Manyberries Pipeline.

BUSINESS RISKS

The risks identified below are specific to the Liquids Pipelines business. General risks that affect the Company as a whole are described under *Risk Management.*

Supply and Demand

The expansion of the Company's liquids pipelines depends on the supply of, and demand for, crude oil and other liquid hydrocarbons from Western Canada. Supply, in turn, depends on a number of variables, including the price of crude oil and bitumen, the availability and cost of capital and labour for oil sands projects, the price of natural gas used for steam production and changes in plans by shippers. Supply risk to existing facilities is largely mitigated given the Company's throughput insensitive commercial terms or cost of service arrangements on many of its Liquids Pipelines assets. Demand depends, among other things, on weather, gasoline price and consumption, manufacturing levels, alternative energy sources and global supply disruptions. Crude oil price volatility has caused some oil sands producers to cancel or defer projects that were planned to commence over the next decade. If the rate of crude oil production from the WCSB declines, immediate need for new pipelines infrastructure will likely decline.

Also, shippers are not required to enter into long-term shipping commitments on Enbridge's mainline system; rather, monthly volume nominations are accepted. The Company's existing right-of-way provides a competitive advantage as it can be difficult and costly to obtain new rights-of-way for new pipelines. The ITS and Terrace Agreement as well as the Southern Access and Alberta Clipper agreements on the Enbridge System provide throughput protection which insulates the Company from negative volume fluctuations beyond its control. The Lakehead System, owned by EEP, has no similar throughput protection on its base or Terrace systems, but does on its SEP II, Southern Access and Alberta Clipper expansions.

Competition

Competition among existing pipelines is based primarily on the cost of transportation, access to supply, the quality and reliability of service, contract carrier alternatives and proximity to markets. Other competing carriers are available to ship western Canadian liquids hydrocarbons to markets in either Canada or the United States. Competition also arises from new pipeline proposals that provide access to market areas currently served by the Company's liquids pipelines. One such competing project is expected to begin commercial operations in early 2010 and will serve markets at Wood River, Illinois and Cushing, Oklahoma. This pipeline has an initial capacity of 435,000 bpd and an ultimate stated capacity of 591,000 bpd. Commercial support has also been announced to construct additional ex-Alberta capacity of 500,000 bpd to Nederland, Texas, for an in-service date during 2012. Competing alternatives for delivering western Canadian liquid hydrocarbons into the United States or other markets could erode shipper support for current or future expansion. However, the Company believes that its liquids pipelines provide attractive options to producers in the WCSB due to its competitive tolls and multiple delivery and storage points. Increased competition could arise from new feeder systems servicing the same geographic regions as the Company's feeder pipelines.

The Company continues to adapt to the changes in its business environment. Enbridge is committed to performance excellence and is focused on becoming more efficient, more collaborative, more innovative and more cost effective so that the Company can pass those benefits on to its customers through service, savings, reliability and responsiveness.

Potential Pressure Restrictions

The Company's liquids systems consist of individual pipelines of varying ages. With appropriate inspection and maintenance, the physical life of a pipeline is indefinitely long; however, as pipelines age the level of expenditures required for inspection and maintenance may increase. Temporary pressure restrictions have been established on some sections of certain pipelines pending completion of specific inspection and repair programs. Pressure restrictions may from time to time be established on the Company's pipelines. Pressure restrictions reduce the available capacity of the applicable line segment and could result in a loss of throughput if and when the full capacity of that line segment would otherwise have been utilized. Pressure restrictions to date have not given rise to any significant loss of throughput. While the Enbridge System is volume-protected, EEP's Lakehead System and certain other pipelines would be adversely affected by any pressure restrictions that do reduce volumes transported.

Regulation

The Enbridge System and other liquids pipelines are subject to the actions of various regulators, including the NEB. Actions of the regulators related to tariffs, tolls and facilities impact earnings from those operations. The NEB historically prescribed a benchmark multi-pipeline rate of return on common equity, which is 8.52% in 2010 (2009 – 8.57%; 2008 – 8.71%). To the extent the NEB rate of return fluctuates, a portion of the Enbridge System and other liquids pipelines earnings will change. The Company believes that regulatory risk is reduced through the negotiation of long-term agreements with shippers, such as the ITS, Terrace Agreement and agreements for projects currently under construction, including Alberta Clipper, which will govern the majority of the segment's assets.

National Energy Board Decision

In October 2009, the NEB released a decision stating the generic multi-pipeline formula used to determine allowed ROE for pipeline companies is no longer in effect. The formula will not be replaced; instead returns will be determined through negotiated settlement between shippers and pipelines. As the formula is referenced in some current industry settlements, the NEB will continue to publish the generic ROE for 2010 and 2011, and if requested will continue to publish it post-2011.

Certain of the Company's Liquids assets are regulated by the NEB and reference the multi-pipeline rate. The Company does not expect there will be a material financial impact as a result of this decision.

Natural Gas Delivery and Services

EARNINGS

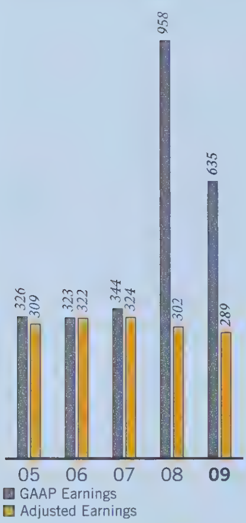
(millions of Canadian dollars)	2009	2008	2007
Enbridge Gas Distribution	**129**	123	115
Noverco	**19**	20	18
Other Gas Distribution	**26**	23	19
Enbridge Offshore Pipelines (Offshore)	**29**	7	22
Alliance Pipeline US	**27**	25	28
Vector Pipeline	**16**	14	15
Aux Sable	**26**	28	11
Energy Services	**29**	17	6
International	**–**	52	90
Other	**(12)**	(7)	–
Adjusted Earnings	**289**	302	324
EGD–colder than normal weather	**17**	23	14
EGD–interest income on GST refund	**7**	–	–
EGD–provision for one-time charges	**–**	(3)	–
EGD–impact of tax changes	**21**	–	20
Noverco–impact of tax changes	**6**	–	7
Offshore–property insurance recoveries from hurricanes, net of costs incurred	**4**	–	5
Alliance Pipeline US–shipper claim settlement	**–**	2	–
Aux Sable–unrealized derivative fair value gains/(losses)	**(36)**	56	(28)
Aux Sable–loan forgiveness	**7**	–	–
Energy Services–unrealized derivative fair value gains/(losses)	**3**	23	(3)
Energy Services–SemGroup and Lehman credit recovery/(loss)	**1**	(6)	–
International–gain on sale of investments in OCENSA and CLH	**329**	556	5
Other–asset impairment loss	**(10)**	–	–
Other–adoption of new accounting standard	**(3)**	–	–
Other–gain on sale of investment in Inuvik Gas	**–**	5	–
Earnings	**635**	958	344

Adjusted earnings from Natural Gas Delivery and Services were $289 million for the year ended December 31, 2009 compared with $302 million for the year ended December 31, 2008. The decreased earnings were substantially due to the sale of CLH in June 2008 and OCENSA in March 2009, offset by higher volumes, including contributions from Shenzi, since its in-service date in April 2009, and Thunder Horse, both within Offshore, favourable foreign exchange, as well as increased adjusted earnings at EGD, Energy Services and Aux Sable.

Adjusted earnings from Natural Gas Delivery and Services were $302 million for the year ended December 31, 2008 compared with $324 million for the year ended December 31, 2007. The decrease in adjusted earnings was substantially due to continuing natural production declines and lost revenue and clean up costs related to Hurricanes Gustav and Ike in Offshore, as well as the sale of CLH in International on June 17, 2008. The decreased earnings for the year ended December 31, 2008 were partially offset by customer growth and higher ancillary revenues at EGD, customer growth at Enbridge Gas New Brunswick (EGNB) within Other Gas Distribution and improved financial performance at Energy Services and Aux Sable.

Natural Gas Delivery and Services earnings were impacted by the following non-recurring or non-operating adjusting items:

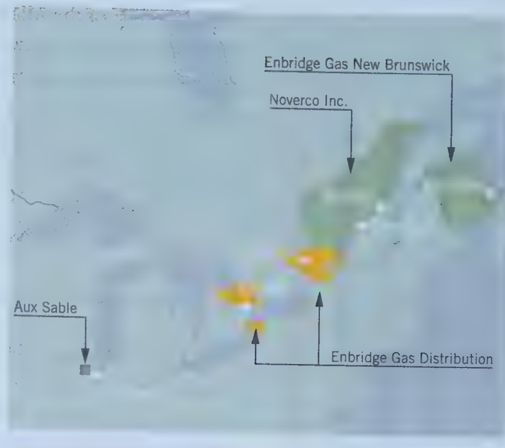
- EGD earnings are adjusted to reflect the impact of colder weather.
- Earnings from EGD for 2009 included interest income of $7 million related to the recovery of excess GST remitted to Canada Revenue Agency.
- Earnings from EGD for 2008 included a $3 million provision for one-time charges to better align certain operating practices with its strategy under incentive regulation (IR).
- In 2009 and 2007, earnings from EGD and Noverco reflect the impact of favourable tax rate changes.
- Earnings for the year ended December 31, 2008 were impacted by $2 million in proceeds received by Alliance Pipeline US from the settlement of a claim against a former shipper which repudiated its capacity commitment.
- Offshore earnings for the year ended December 31, 2009 and 2007 included insurance proceeds of $4 million and $5 million, respectively, related to the replacement of damaged infrastructure as a result of the 2008 and 2005 hurricanes.
- Aux Sable earnings for each period reflected unrealized fair value changes on derivative financial instruments used to risk manage fractionation margin upside on natural gas processing volumes. Similar to Energy Services, these non-cash items arose due to the revaluation of financial derivatives used to "lock in" the profitability of forward contracted prices.
- Earnings for the year ended December 31, 2009 from Aux Sable reflected a $7 million gain from a loan forgiveness related to a negotiated settlement with a counterparty in bankruptcy proceedings.
- Energy Services earnings for 2009 and 2008 reflected unrealized fair value gains and losses resulting from the revaluation of inventory and the revaluation of largely offsetting financial derivatives used to "lock-in" the profitability of forward transportation and storage transactions.
- Energy Services earnings for the year ended December 31, 2008 included a $6 million write-off as a result of bankruptcies by SemGroup and Lehman Brothers. In fiscal 2009, the Company received a $1 million recovery from SemGroup.
- On March 17, 2009, the Company sold its investment in OCENSA, a crude oil export pipeline in Colombia, for proceeds of $512 million, resulting in a gain of $329 million. On June 17, 2008, the Company sold its investment in CLH for proceeds of $1,380 million, resulting in a gain of $556 million.
- Other earnings for 2009 reflected a $10 million asset impairment loss, including goodwill.
- Other reflected the write-off of $3 million in deferred development costs as a result of adopting a change in accounting standards, effective January 1, 2009.
- A $5 million gain on sale of investment in Inuvik Gas was reflected in earnings from Other for the year ended December 31, 2008.



Natural Gas Delivery and Services Earnings
(millions of Canadian dollars)

ENBRIDGE GAS DISTRIBUTION

EGD is Canada's largest natural gas distribution company and has been in operation for more than 160 years. It serves approximately 1.9 million customers in central and eastern Ontario and parts of northern New York State. EGD's utility operations are regulated by the Ontario Energy Board (OEB) and by the New York State Public Service Commission.



Gas Distribution and Services

Incentive Regulation

In 2008, EGD moved to an IR methodology. The objectives of the IR plan are as follows:

- reduce regulatory costs;
- provide incentives for improved efficiency;
- provide more flexibility for utility management; and
- provide more stable rates.

Under the IR framework, Enbridge is allowed to earn 100 bps over the base regulated return. Through various productivity enhancements, any return over this 100 bps must be shared with customers on an equal basis. Enbridge estimates the customer portion of 2009 earnings over the allowed threshold at $19 million (2008 – $6 million).

Rate Adjustment Applications

In September 2009, EGD filed an application with the OEB to adjust rates for 2010 pursuant to the approved IR formula, to increase funding of its pension plans and to seek approval for specific changes to the Rate Handbook. The OEB issued a first procedural order in October 2009, in which the OEB indicated that it would consider its jurisdiction with regard to inclusion of green energy related projects within the regulated operations of EGD. The OEB issued a decision in December 2009 which effectively prevents the inclusion of such activities in rate-making for the purposes of setting 2010 rates. As a result of this decision, in 2010, EGD will seek clarification of the OEB's broader policies with respect to such investments and activities.

In September 2008, EGD filed an application with the OEB to adjust rates for 2009 pursuant to the approved IR formula and to seek approval for specific changes to the Rate Handbook. A settlement agreement containing all applied for aspects of the formulaic component of the IR rate setting process was approved by the OEB in December 2008. EGD received a fiscal 2009 final rate order from the OEB in February 2009 approving the implementation of a rate change effective April 1, 2009, which enabled EGD to recover the approved revenues as if rates were effective January 1, 2009.

New Customer Information System (CIS) Implemented

In September 2009, EGD successfully implemented its new CIS, which replaced the legacy system. EGD expects to fully recover in rates the total cost of the project in accordance with an agreement with customer groups that was approved by the OEB in 2007.

Green Energy Initiatives

In September 2009, Ontario's Minister of Energy and Infrastructure issued a Directive that permits EGD to own and operate stationary fuel cells, wind, water, biomass, biogas, solar and geothermal energy generation facilities up to 10 MW in capacity. EGD will also be permitted to own and operate district and distributed energy systems, including facilities that produce power and thermal energy from a single source. Finally, the Minister's Directive permits EGD to own and operate assets that would assist the Government of Ontario in achieving its goals in energy conservation, including assets related to solar-thermal water and ground source heat pumps.

In the absence of the Minister's Directive, the Company's Undertakings to the Lieutenant Governor in Council would not have permitted EGD to engage in the foregoing activities directly. EGD is well positioned to take on an increasing role in this area and is looking to expand its efforts to explore and pursue alternative and/or renewable energy technologies subject to OEB approval, where appropriate. While the Directive permits EGD to engage in such activities, in December 2009 the OEB determined that it would not allow such activities to be included in rate-making for the purposes of setting 2010 rates. As a result of this decision, EGD will seek clarification of the OEB's broader policies with respect to such investments and activities in 2010.

Enbridge Gas Distribution—Number of Active Customers
(thousands)

Unregulated Storage Services

The deregulation of new natural gas storage in Ontario, coupled with the growing need for high-deliverability storage services by gas-fired power generators and other users, has created unregulated storage growth opportunities for EGD. As of December 31, 2009, EGD has expanded its storage capacity by 6% (5.5 bcf) and sold unregulated storage services into the storage market. A second expansion, amounting to an additional 2 bcf of capacity, is planned to be in service in 2010.

Results of Operations

Adjusted earnings for the year ended December 31, 2009 were $129 million compared with $123 million for the year ended December 31, 2008. The increase in EGD's adjusted earnings was primarily due to customer growth and lower interest expense, offset by higher operating costs and estimated accrued earnings sharing with customers under the current IR term caused primarily by a reduced rate base resulting from lower cost gas in storage.

Adjusted earnings for the year ended December 31, 2008 were $123 million compared with $115 million for the year ended December 31, 2007. EGD's increased adjusted earnings for 2008 reflect early success during its first of five years under IR, specifically through customer growth and higher ancillary revenues.

EGD earnings were impacted by the following non-recurring or non-operating adjusting items:

- Earnings for each period are adjusted to reflect the impact of colder weather. Weather is a significant driver of delivery volumes given that a significant portion of EGD customers use natural gas for space heating.
- Earnings for the year ended December 31, 2009 included interest income of $7 million related to the recovery of excess GST remitted to Canada Revenue Agency.
- In 2008, earnings included a $3 million provision for one-time charges to better align certain operating practices with its strategy under IR.
- Earnings for the year ended December 31, 2009 and 2007 reflected an increase of $21 million and $20 million, respectively, related to favourable tax rate changes.

Business Risks

The risks identified below are specific to EGD. General risks that affect the Company as a whole are described under *Risk Management*.

Regulatory Risk

The formula currently approved by the OEB for determination of the ROE, which is embedded and escalated within rates over the IR period, is based on the OEB's risk assessment of EGD for the 2007 fiscal year.

The OEB issued a report in December 2009 indicating several changes to the cost of capital for Ontario's regulated utilities. The new policy guidelines established a new base level ROE of 9.75% for all of Ontario's utilities for the 2010 rate year. The treatment of deemed capital structure was left unchanged. A new annual adjustment formula was also established which will change annually with changes in the interest rates on long-term Canada bonds and Canadian A-Rated utility bonds.

EGD anticipates that the new ROE policy guidelines will be applied to the determination of the annual earnings sharing mechanism for 2010 and for the remainder of the IR term. The company also anticipates applying the new ROE policy guidelines to the determination of rates after the conclusion of the IR term, for the rate year beginning 2013.

The settlement allows certain categories of expense, added at cost of service base amounts, and uncontrollable external factors in the IR formula, which will permit EGD to recover, with OEB approval, certain costs that are beyond management control, but are necessary for the maintenance of its services. The settlement also includes a mechanism to end the IR plan and return to cost of service if there are significant and unanticipated developments that threaten the sustainability of the IR plan. The above noted terms set out in the settlement mitigate EGD's risk to factors beyond management's control.

EGD does not profit from the sale of natural gas nor is it at risk for the difference between the actual cost of natural gas purchased and the price approved by the OEB. This difference is deferred as a receivable from or payable to customers until the OEB approves its refund or collection. EGD monitors the balance and its potential impact on customers and will request interim rate relief that will allow EGD to recover or refund the natural gas cost differential. EGD has a quarterly rate adjustment mechanism in place for the natural gas. This allows for the quarterly adjustment of rates to reflect changes in natural gas prices. Adjustments are subject to prior approval by the OEB.

Volume Risks

Since customers are billed on both a fixed charge and on a volumetric basis, EGD's ability to collect its total IR formula revenue depends on achieving the forecast distribution volume established in the rate-making process. Under IR, volume forecasts are reviewed and approved by the OEB annually. The probability of realizing such volume is contingent upon four key forecast variables: weather, economic conditions, pricing of competitive energy sources and growth in the number of customers. Over the life of the current IR agreement, the portion of fixed charges will increase thereby reducing this risk.

Weather is a significant driver of delivery volumes, given that a significant portion of EGD's customer base uses natural gas for space heating. For the years ended December 31, 2009, 2008 and 2007, colder than normal weather impacted earnings by $17 million, $23 million and $14 million, respectively.

Distribution volume may also be impacted by the increased adoption of energy efficient technologies, along with more efficient building construction, that continues to place downward pressure on consumption. In addition, conservation efforts by customers further contribute to the decline in annual average consumption. On average, EGD has seen a 1.3% annual decline in residential use year-over-year between 1998 and 2008. During the IR term, the ability of EGD to annually adjust distribution volumes for rate-setting provides a mechanism to protect the company from exposure to declining average use. Further, once rates are set for the year, any incremental decline or benefit (if any) in average use, compared to the basis used for rate-setting in the most recent year, is recorded as a regulatory deferral for future collection from, or refund to, customers, to the extent this relates to residential and small commercial customers.

Sales and transportation of gas for customers in the residential and commercial sectors account for approximately 81% (2008 – 79%) of total distribution volume. Sales and transportation service to large volume commercial and industrial customers is more susceptible to prevailing economic conditions.

As well, the pricing of competitive energy sources affects volume distributed to these sectors as some customers have the ability to switch to an alternate fuel. Customer additions are important to all market sectors as continued expansion adds to the total consumption of natural gas.

Even in those circumstances where EGD attains its total forecast distribution volume, it may not earn its expected ROE due to other forecast variables such as the mix between the higher margin residential and commercial sectors and the lower margin industrial sector.

This distribution volume risk for general service customers is mitigated by the average use true-up variance account that was established under the IR Settlement Agreement. This variance account enables recovery from or repayment to customers of amounts representing variances in the actual and forecast average use by general service customers. EGD remains at risk of distribution volumes for large volume contract commercial and industrial customers.

NOVERCO

Enbridge owns an equity interest in Noverco through ownership of 32.1% of the common shares and a cost investment in preferred shares. Noverco is a holding company that owns approximately 71.0% of Gaz Metro Limited Partnership (Gaz Metro), a publicly traded gas distribution company operating in the province of Quebec and in the state of Vermont.

Weather variations do not affect Noverco's earnings as Gaz Metro is not exposed to weather risk. A significant portion of the Company's earnings from Noverco is in the form of dividends on its preferred share investment, which is based on the yield of 10-year Government of Canada bonds plus 4.34%.

Results of Operations

Noverco adjusted earnings were $19 million for the year ended December 31, 2009, comparable to $20 million for the year ended December 31, 2008 and $18 million for the year ended December 31, 2007. Noverco earnings for the year ended December 31, 2009 and 2007 reflected an increase of $6 million and $7 million, respectively, related to favourable tax rate changes.

OTHER GAS DISTRIBUTION

Other Gas Distribution includes natural gas distribution utility operations in Quebec, New Brunswick and northern New York State. The largest utility included in this group of assets is EGNB (70.9% owned and operated by the Company) which owns the natural gas distribution franchise in the province of New Brunswick. EGNB is constructing a new distribution system and has approximately 10,000 customers. Approximately 725 kilometres (450 miles) of distribution main has been installed with the capability of attaching approximately 30,000 customers.

Results of Operations

Other Gas Distribution earnings were $26 million for the year ended December 31, 2009, comparable to $23 million for the year ended December 31, 2008. Earnings for the year ended December 31, 2008 were $4 million higher than earnings for the year ended December 31, 2007, mainly as a result of franchise customer growth in EGNB.

EGNB is regulated by the New Brunswick Energy and Utilities Board (EUB). As it is currently in the development period, EGNB's cost of service exceeds its distribution revenues. The EUB has approved the deferral of the shortfall between distribution revenues and the cost of service during the development period for recovery in future rates. This recovery period is expected to start in 2010 and end no sooner than December 31, 2040. On December 31, 2009, the regulatory deferral asset was $155 million (2008–$133 million).

ENBRIDGE OFFSHORE PIPELINE

Offshore is comprised of 13 natural gas gathering and FERC-regulated transmission pipelines and one oil pipeline in five major corridors in the Gulf of Mexico, extending to deepwater frontiers. These pipelines include almost 1,500 miles (2,400 kilometres) of underwater pipe and onshore facilities and transported approximately 2.3 bcf/d during 2009. Offshore currently moves approximately 50% of offshore deepwater gas production through its systems in the Gulf of Mexico.

Enbridge Offshore Pipelines

Transportation Contracts

The primary shippers on the Offshore systems are producers who execute life-of-lease commitments in connection with transmission and gathering service contracts. In exchange, Offshore provides firm capacity for the contract term at an agreed upon rate. The throughput volume generally reflects the lease's maximum sustainable production. The transportation contracts allow the shippers to define a maximum daily quantity (MDQ), which corresponds with the expected production life. The contracts typically have minimum throughput volumes which are subject to take-or-pay criteria, but also provide the shippers with flexibility, subject to advance notice criteria, to modify the projected MDQ schedule to match current deliverability expectations.

Increasingly, and reflecting recent setbacks from hurricanes, transportation tariffs on our largest system includes surcharge recoveries to cover increased operating and repair costs.

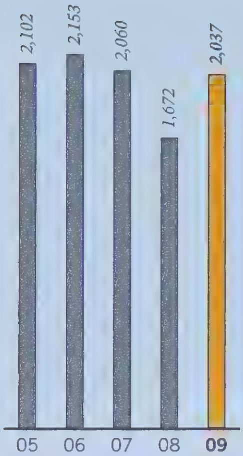
The long-term transport rates established in the gathering and transmission service agreements are generally market-based but are established using a cost of service methodology, which includes operating cost, projected revenue generation directly tied to production deliverability and the appropriate cost of capital.

The business model utilized on a go forward basis and included in the WRGGS and Big Foot commercially secured projects differs from the historic model. These new projects have a base level return which is locked in by take or pay commitments. If volumes reach producer anticipated levels the return on these projects will increase. In addition, Enbridge has minimal capital cost risk on these projects and still has the life-of-lease commitments included in commercial agreements.

Results of Operations

Adjusted earnings for the year ended December 31, 2009 in Offshore were $29 million compared with $7 million for the year ended December 31, 2008. Offshore adjusted earnings increased due to higher volumes, including contributions from Shenzi, since its in-service date in April 2009, and Thunder Horse, since its in-service date of June 2008, as well as favourable foreign exchange rates. Offshore adjusted earnings for 2009 included $4 million in insurance proceeds collected during the second and fourth quarters, which were partial reimbursement for business interruption lost revenues and operating expenses associated with Hurricane Ike in 2008.

Offshore adjusted earnings for the year ended December 31, 2008 were $7 million compared with $22 million for the year ended December 31, 2007. Offshore adjusted earnings decreased as a result of continuing natural production declines as well as approximately $11 million in lost revenue and clean up costs related to Hurricanes Gustav and Ike. These decreases were partially offset by stand-by fees on the Neptune oil and gas pipelines which came into service in the fourth quarter of 2007, as well as contributions from Atlantis and Thunder Horse platform volumes. Also, adjusted earnings for the year ended December 31, 2008 included approximately $2 million (2007 – $6 million) from business interruption insurance proceeds related to lost revenue in 2005 and 2006 as a result of the 2005 hurricanes.



Enbridge Offshore Pipelines—Average Throughput Volumes
(millions of cubic feet per day)

Earnings for 2009 and 2007 included insurance proceeds of $4 million and $5 million, respectively, related to the replacement of damaged infrastructure as a result of the 2008 and 2005 hurricanes.

Business Risks

The risks identified below are specific to Offshore. General risks that affect the Company as a whole are described under *Risk Management*.

Weather

Adverse weather, such as hurricanes, may impact Offshore financial performance directly or indirectly. Direct impacts may include damage to Offshore facilities resulting in lower throughput and inspection and repair costs. Indirect impacts include damage to third party production platforms, onshore processing plants and pipelines that may decrease throughput on Offshore systems.

Effective June 1, 2009, Offshore's insurance policy no longer includes coverage related to named windstorms, such as hurricanes. The decision to exclude this coverage from the policy, pending future years' analysis, was a result of significant increases in insurance premiums and deductibles. As a result of the change in coverage, damage caused by future hurricanes could more significantly impact Offshore's financial performance. Partially offsetting this exposure, the Stingray Pipeline system implemented, as part of a 2009 FERC rate case settlement, an event surcharge mechanism to allow recovery from shippers for hurricane damage.

Competition

There is competition for new and existing business in the Gulf of Mexico. Offshore has been able to capture key opportunities, positioning it to more fully utilize existing capacity. Offshore serves a majority of the strategically located deepwater host platforms and its extensive presence in the deepwater Gulf of Mexico has Offshore well positioned to generate incremental revenues, with modest capital investment, by transporting production from sub-sea development of smaller fields tied back to existing host platforms. Offshore is also able to construct pipelines to transport crude oil, diversifying the risk of declining production, as demonstrated with the newly constructed Neptune crude oil lateral and the recently announced Big Foot Oil Pipeline. Given rates of decline, Offshore pipelines typically have available capacity, resulting in significant competition for new developments in the Gulf of Mexico.

Regulation

The transportation rates on many of Offshore's transmission pipelines are generally based on a regulated cost of service methodology and are subject to regulation by the FERC. These rates are subject to challenge from time-to-time.

Other Risks

Other risks directly impacting financial performance include underperformance relative to expected reservoir production rates, delays in project start-up timing, changes in plans by shippers and capital expenditures in excess of those estimated. Capital risk is mitigated in some circumstances by having area producers as joint venture partners, through cost of service tolling arrangements and pre-arranged terms in commercial agreements. Start-up delays are mitigated by the right to collect stand-by fees.

ALLIANCE PIPELINE US

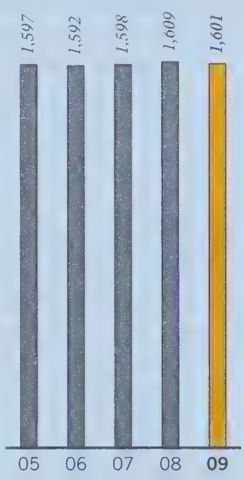
The Alliance System (Alliance), which includes both the Canadian and United States portions of the pipeline system, consists of an approximately 3,000-kilometre (1,875-mile) integrated, high-pressure natural gas transmission pipeline system and an approximately 730-kilometre (455-mile) lateral pipeline system and related infrastructure. Alliance transports liquids-rich natural gas from northeast British Columbia and northwest Alberta to Channahon, Illinois. The pipeline has firm service shipping contract capacity to deliver 1.325 bcf/d. Enbridge owns 50% of Alliance Pipeline US, while EIF, described under Sponsored Investments, owns 50% of Alliance Pipeline Canada.

Alliance connects with Aux Sable, of which Enbridge owns 42.7%, a NGLs extraction facility in Channahon, Illinois. The natural gas may then be transported to two local natural gas distribution systems in the Chicago area and five interstate natural gas pipelines, providing shippers with access to natural gas markets in the midwestern and northeastern United States and eastern Canada.

In 2009, Pecan Pipeline, a gathering pipeline owned by a third party, was connected to a new gas receipt point on Alliance near Towner, North Dakota. This pipeline will bring associated rich gas from the Bakken formation on to Alliance. The new receipt point went into service in January 2010, with an initial volume of 40 mmcf/d, which will increase to 80 mmcf/d one year after the initial in-service date.

Transportation Contracts

Alliance has long-term, take-or-pay contracts through 2015 to transport 1.305 bcf/d of natural gas or 98.5% of the total contracted capacity. Alliance has an additional 20 million cubic feet per day (mmcf/d) of natural gas contracted through 2010 which is expected to be remarketed upon expiry. These contracts permit Alliance to recover the cost of service, which includes operating and maintenance costs, the cost of financing, an allowance for income tax, an annual allowance for depreciation and an allowed ROE of 11.5%. Each long-term contract may be renewed upon five years notice for successive one-year terms beyond the original 15-year primary term. Alliance Pipeline US operations are regulated by the FERC.

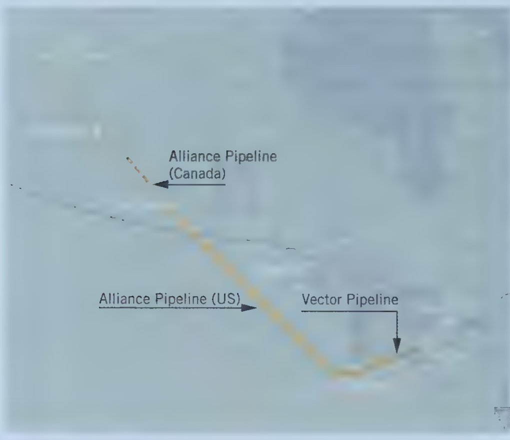


Alliance Pipeline US – Average Throughput Volumes
(millions of cubic feet per day)

Depreciation expense included in the cost of service is based on negotiated depreciation rates contained in the transportation contracts, while depreciation expense in the financial statements is recorded on a straight-line basis at 4% per annum. Negotiated depreciation expense is generally less than the financial statement amount at the beginning of the contract and higher than straight-line depreciation in the later years of the shipper transportation agreements. This difference results in recognition of a long-term receivable, referred to as deferred transportation revenue, that is expected to be recovered from shippers beginning in 2009 for Alliance Pipeline US and 2011 for Alliance Pipeline Canada. As at December 31, 2009, $151 million (US$144 million) (2008–$182 million (US$149 million)) was recorded as deferred transportation revenue.

Alliance Pipeline Recontracting Strategy

Alliance continues to be fully contracted on a firm service basis and is expected to run at or near full capacity until at least 2015 when existing long-term shipper contracts expire. Alliance is developing strategies to maximize its competitiveness, post-2015, in light of falling export production from western Canada and the potential for surplus export pipeline capacity. Alliance is well placed to benefit from incremental unconventional volumes from shale plays in British Columbia, and is currently evaluating opportunities to expand its service offerings in this area.



Natural Gas Pipelines

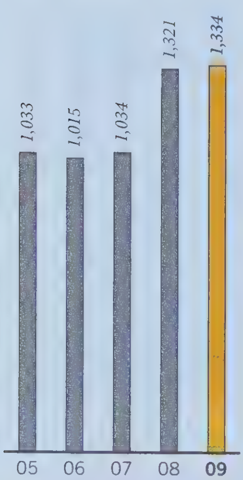
Results of Operations

Alliance Pipeline US adjusted earnings were $27 million for the year ended December 31, 2009, comparable to $25 million for the year ended December 31, 2008 and $28 million for the year ended December 31, 2007. The slight variability in adjusted earnings each year was primarily due to United States dollar foreign exchange fluctuations.

Earnings for the year ended December 31, 2008 included $2 million in proceeds received from the settlement of a claim against a former shipper which repudiated its capacity commitment.

VECTOR PIPELINE

The Company provides operating services to, and holds a 60% joint venture interest in, Vector Pipeline, which transports natural gas from Chicago, Illinois to Dawn, Ontario. Vector Pipeline has the capacity to deliver a nominal 1.3 bcf/d and is operating at or near capacity.



Vector Pipeline—Average Throughput Volumes

(millions of cubic feet per day)

Vector Pipeline's primary sources of supply are through interconnections with Alliance and the Northern Border Pipeline in Joliet, Illinois. Approximately 55% of the long haul capacity of Vector Pipeline is committed through 15-year firm transportation contracts at rates negotiated with the shippers and approved by the FERC. The remaining capacity is sold at market rates and at various term lengths. The total long haul capacity of Vector is approximately 90% committed through 2015. Transportation service is provided through a number of different forms of service agreements such as Firm Transportation Service and Interruptible Transportation Service. Vector Pipeline is an interstate natural gas pipeline with FERC and NEB approved tariffs establishing rates, terms and conditions governing its service to customers. On the United States portion of Vector, tariff rates are determined using a cost of service methodology and tariff changes may only be implemented upon approval by the FERC. For 2009, the FERC approved maximum tariff rates include a weighted average after-tax ROE component of 11.07% (2008–11.04%; 2007–10.75%). On the Canadian portion, Vector Pipeline is required to file its negotiated tolls calculation with the NEB on an annual basis. Tolls are calculated on a levelized basis that include a rate of return incentive mechanism based on construction costs and are subject to a rate cap. In 2009, maximum tariff tolls include a ROE component of 10.48% after-tax.

Results of Operations

Vector Pipeline adjusted earnings were $16 million for the year ended December 31, 2009, comparable to $14 million for the year ended December 31, 2008 and $15 million for the year ended December 31, 2007.

Business Risks

The risks identified below are specific to both Alliance Pipeline US and Vector Pipeline. General risks that affect the entire Company are described under *Risk Management*.

Supply and Demand

Advances in clean-coal technology and nuclear power as sources of power generation may reduce growth in natural gas demand over the longer term. However, demand is supported by rising use of gas for power generation. Currently, pipeline capacity out of the WCSB exceeds supply. Alliance Pipeline US and Vector Pipeline have been unaffected by this excess capacity environment mainly because of long-term capacity contracts extending to 2015. Vector Pipeline's interruptible capacity could be negatively impacted by the basis (location) differential in the price of natural gas between Chicago and Dawn, Ontario relative to the transportation toll.

Exposure to Shippers

The failure of shippers to perform their contractual obligations could have an adverse effect on the cash flows and financial condition of Alliance Pipeline US and Vector Pipeline. To reduce this risk, Alliance Pipeline US and Vector Pipeline monitor the creditworthiness of each shipper and receive collateral for future shipping tolls should a shipper's credit position not meet tariff requirements. These pipelines also have diverse groups of long-term transportation shippers, which include various gas and energy distribution companies, producers and marketing companies, further reducing the exposure.

Competition

Alliance Pipeline US faces competition for pipeline transportation services to the Chicago area from both existing and proposed pipeline projects. Competing pipelines provide natural gas transportation services from the WCSB to distribution systems in the Midwestern United States. In addition, there are several proposals to upgrade existing pipelines serving these markets. Any new or upgraded pipelines could either allow shippers greater access to natural gas markets or offer natural gas transportation services that are more desirable than those provided by Alliance. Shippers on Alliance Pipeline US have access to additional high compression delivery capacity at no additional cost, other than fuel requirements, serving to enhance the competitive position of Alliance Pipeline US.

Vector Pipeline faces competition for pipeline transportation services to its delivery points from new supply sources and traditional low cost pipelines, which could offer transportation that is more desirable to shippers because of cost, supply location, facilities or other factors. Vector Pipeline has mitigated this risk by entering into long-term firm transportation contracts, which expire starting in November 2015, for approximately 87% of its capacity. The remaining contracts expire at various times starting in April 2012. Certain long-term firm contracts (55% of capacity) provide for additional compensation to Vector Pipeline if shippers do not extend their contracts beyond the initial term ending November 2015. The effectiveness of these mitigating factors is evidenced by the increased utilization of the pipeline since its construction, despite the presence of transportation alternatives.

Regulation

Both Vector Pipeline and Alliance Pipeline US operations are regulated by the FERC. On a yearly basis, following consultation with shippers, Alliance Pipeline US files its annual rates with the FERC for approval.

FERC has intensified its oversight of financial reporting, risk standards and affiliate rules and has issued new standards on managing gas pipeline integrity. The Company continues ongoing dialogue with regulatory agencies and participates in industry lobby groups to ensure it is informed of emerging issues in a timely manner.

AUX SABLE

Enbridge owns 42.7% of Aux Sable, a NGLs extraction and fractionation business near Chicago, Illinois. Aux Sable owns and operates a plant at the terminus of Alliance. The plant extracts NGLs from the energy-rich natural gas transported on Alliance, as necessary to meet the requirements of downstream distribution companies, which require natural gas with less NGLs, or lower heat content; and to take advantage of positive commodity price spreads.

Aux Sable has an agreement with BP to sell its NGLs production to BP. In return, BP pays Aux Sable a fixed annual fee and a share of any net margin generated from the business in excess of specified natural gas processing margin thresholds (the upside sharing mechanism). In addition, BP compensates Aux Sable for all operating, maintenance and capital costs associated with the Aux Sable facilities subject to certain limits on capital costs. BP supplies, at its cost, all make-up gas and fuel supply gas to the Aux Sable facilities and is responsible for the capacity on the Alliance Pipeline held by an Aux Sable affiliate, at market rates. The agreement is for an initial term of 20 years, expiring December 21, 2025 and may be extended by mutual agreement for 10-year terms.

Results of Operations

Adjusted earnings for the year ended December 31, 2009 were $26 million compared with $28 million for the year ended December 31, 2008. Aux Sable adjusted earnings decreased due to unexpected plant outages during the fourth quarter of 2009.

Adjusted earnings for the year ended December 31, 2008 were $28 million compared with earnings of $11 million for the year ended December 31, 2007. Aux Sable adjusted earnings increased due to strong fractionation margins and enhanced plant performance, in addition to favourable risk management positions, which enabled the Company to recognize earnings from the upside sharing mechanism.

Aux Sable earnings reflected the following non-recurring or non-operating adjusting items:

- Earnings for each period reflected unrealized fair value changes on derivative financial instruments used to risk manage fractionation margin upside on natural gas processing volumes. These non-cash amounts arose due to the revaluation of financial derivatives used to “lock in” the profitability of forward contracted prices.
- Earnings for 2009 included $7 million related to a negotiated settlement with a counterparty in bankruptcy proceedings.

ENERGY SERVICES

Energy Services includes Gas Services and Tidal Energy, the Company’s energy marketing businesses. Gas Services markets natural gas to optimize Enbridge’s commitments on the Alliance and Vector pipelines. It also has a growing business of providing fee-for-service arrangements for third parties, leveraging its marketing expertise and access to contracted transportation capacity. Capacity commitments as of December 31, 2009 were 33 mmcf/d on Alliance (3% of total capacity) and 104 mmcf/d on Vector Pipeline (9% of total capacity). Capacity commitments as of December 31, 2008 were 33 mmcf/d on Alliance (3% of total capacity) and 144 mmcf/d on Vector Pipeline (12% of total capacity).

Earnings from Gas Services are dependent upon the basis (location) differentials between Alberta and Chicago, for Alliance, and between Chicago and Dawn, for Vector Pipeline. To the extent the cost of transportation on these two pipelines exceeds the gas commodity basis differential, earnings will be negatively affected.

Tidal Energy provides crude oil and NGLs marketing services for the Company and its customers in a full range of condensate and crude oil types including light sweet, light and medium sours and several heavy grades. Tidal Energy transacts at many of the major North American market hubs and provides its customers with a variety of programs including flexible pricing arrangements, hedging programs, product exchanges, physical storage programs and total supply management. Tidal Energy’s business involves buying, selling, transporting and storing condensate and crude oil. Tidal Energy is primarily a physical barrel marketing company and in the course of its market activities can create modest commodity exposures. Any residual open positions created from this physical business are tightly monitored and must comply with the Company’s formal risk management policies.

Results of Operations

Adjusted earnings from Energy Services increased from $6 million in 2007 to $17 million in 2008 and $29 million in 2009. The increase in adjusted earnings each year is due to higher volumes and the impact of realizing favourable storage and transportation margins.

Energy Services earnings were impacted by the following non-recurring or non-operating adjusting items:

- Earnings for each period reflect unrealized fair value gains and losses resulting from the revaluation of inventory and the revaluation of largely offsetting financial derivatives used to "lock-in" the profitability of forward transportation and storage transactions. During the first quarter of 2009, the Company adopted fair value accounting for inventory held at its commodity marketing businesses.
- Energy Services 2008 earnings included a $6 million write-off as a result of bankruptcies by SemGroup and Lehman Brothers–the full amount of all such receivables was provided for in 2008. In 2009, $1 million was recovered from the SemGroup bankruptcy.

INTERNATIONAL

In 2009, the Company sold its 24.7% interest in OCENSA, a crude oil export pipeline in Colombia. In 2008, the Company sold its 25% equity interest in CLH, Spain's largest refined products transportation and storage business. Both of these investments were sold at very attractive prices and proceeds were utilized in the funding of the North American expansion projects discussed earlier.

Given the disposals of OCENSA and CLH, there are currently minimal operations in International. However, Enbridge continues to actively monitor the international business environment to identify potential new investment opportunities.

Results of Operations

International adjusted earnings for the years ended December 31, 2009, 2008 and 2007 were nil, $52 million and $90 million, respectively. The decrease in adjusted earnings was a result of the sale of OCENSA and CLH discussed above.

International earnings were impacted by the following non-recurring or non-operating adjusting items:

- In March 2009, the Company sold its investment in OCENSA for proceeds of $512 million, resulting in a gain of $329 million.
- In June 2008, the Company sold its investment in CLH for proceeds of $1,380 million, resulting in a gain of $556 million.

OTHER

Results of Operations

The adjusted loss in Other was $12 million in 2009 compared with $7 million in 2008 and nil in 2007. Losses in Other primarily reflected higher business development expenditures and lower earnings from CustomerWorks Limited Partnership (CustomerWorks) which resulted from a smaller customer base.

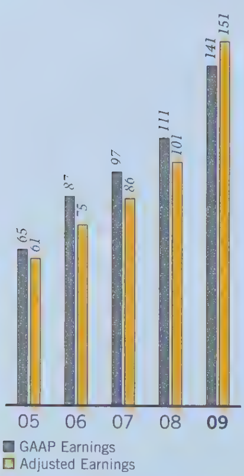
For the year ended December 31, 2009, Other reflected the write-off of $3 million in deferred development costs as a result of adopting a change in accounting standards, effective January 1, 2009, as well as a $10 million asset impairment loss, including goodwill. For the year ended December 31, 2008, Other included a $5 million gain on the sale of the Company's investment in Inuvik Gas.

Sponsored Investments

EARNINGS

	2009	2008	2007
(millions of Canadian dollars)			
Enbridge Energy Partners (EEP)	**99**	60	47
Enbridge Energy, L.P. – Alberta Clipper US (EELP)	**7**	–	–
Enbridge Income Fund (EIF)	**45**	41	39
Adjusted Earnings	**151**	101	86
EEP – unrealized derivative fair value gains/(losses)	**(2)**	6	(6)
EEP – asset impairment loss	**(12)**	–	–
EEP – Lakehead System billing correction	**4**	–	–
EEP – dilution gain on Class A unit issuance	**–**	5	12
EEP – impact of 2008 hurricanes and project write-offs	**–**	(2)	–
EEP – gain on sale of Kansas Pipeline Company (KPC)	**–**	–	3
EIF – Alliance Canada shipper claim settlement	**–**	1	–
EIF – impact of tax rate changes	**–**	–	2
Earnings	**141**	111	97

Adjusted earnings from Sponsored Investments were $151 million for the year ended December 31, 2009 compared with $101 million in 2008 and $86 million in 2007. The increase in adjusted earnings resulted primarily from increased contributions from EEP as a result of positive operating factors and Enbridge's higher ownership interest.

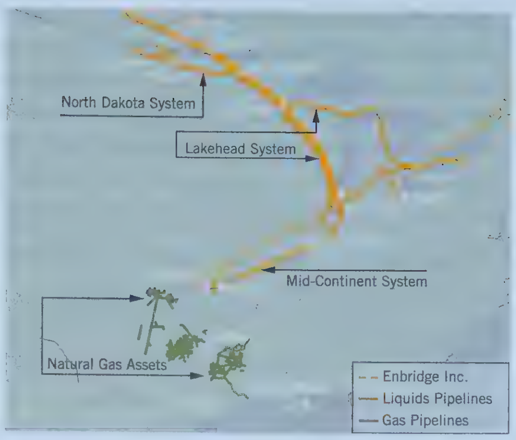


Sponsored Investments Earnings
(millions of Canadian dollars)

Sponsored Investments earnings were impacted by several non-recurring or non-operating adjusting items:

- Earnings from EEP included a change in the unrealized fair value on derivative financial instruments in each period.
- EEP earnings for the year ended December 31, 2009 included an asset impairment loss of $12 million (net to Enbridge) related to the write-down of certain assets.
- Earnings from EEP for year ended December 31, 2009 included a Lakehead System billing correction of $4 million (net to Enbridge) related to services provided in prior periods.
- Earnings in 2008 and 2007 included EEP dilution gains arising because Enbridge did not fully participate in EEP's Class A unit offerings, decreasing Enbridge's ownership interest in EEP to 14.6% as at March 31, 2008. In December 2008, the Company purchased an additional US$500 million in Class A units increasing Enbridge's ownership interest in EEP to 27.0%.
- 2008 earnings from EEP included non-routine costs associated with Hurricanes Gustav and Ike, of which Enbridge's share is $2 million, as well as the write-off of certain projects cancelled due to market conditions.
- In 2007, EEP earnings included Enbridge's $3 million share of the gain on the sale of KPC.
- Earnings from EIF for the year ended December 31, 2008 included proceeds of $1 million from the settlement of a claim against a former shipper on Alliance Canada which repudiated its capacity commitment.
- For the year ended December 31, 2007, EIF earnings reflected $2 million which was due to favourable tax rate changes.

ENBRIDGE ENERGY PARTNERS



Enbridge Energy Partners

EEP owns and operates crude oil and liquid petroleum transportation and storage assets and natural gas gathering, treating, processing, transportation and marketing assets in the United States. Significant assets include the Lakehead System, which is the extension of the Enbridge System in the United States; the Mid-Continent crude oil system consisting of an interstate crude oil pipeline and storage facilities; a crude oil gathering system and interstate pipeline system in North Dakota; and natural gas assets located primarily in Texas.

In the second quarter of 2007, EEP issued partnership units. Because Enbridge did not fully participate in these offerings, dilution gains of $12 million resulted and Enbridge's ownership interest in the Partnership decreased from 16.6% to 15.1%. Enbridge's average ownership interest in 2007 was 15.5%. In March 2008, Enbridge did not participate in EEP's issuance of Class A units, resulting in a $5 million dilution gain and a decrease in ownership interest to 14.6%. In late 2008, Enbridge purchased 16.3 million Class A common units of EEP, resulting in an ownership increase to 27.0%. The Company's average ownership interest in EEP during 2008 was 15.7%. At December 31, 2009, Enbridge's ownership interest in EEP remained at 27.0%.

Distributions

EEP makes quarterly distributions of its available cash to its common unitholders. Under the Partnership Agreement, Enbridge Energy Company, Inc. (EECI), a wholly owned subsidiary of Enbridge, as general partner (GP), receives incremental incentive cash distributions, which represent incentive income, on the portion of cash distributions, on a per unit basis, that exceed certain target thresholds as follows:

	Unitholders including Enbridge	GP Interest
Quarterly Cash Distributions per Unit:		
Up to $0.59 per unit	98%	2%
First target–$0.59 per unit up to $0.70 per unit	85%	15%
Second target–$0.70 per unit up to $0.99 per unit	75%	25%
Over second target–cash distributions greater than $0.99 per unit	50%	50%

In the first three quarters of 2007, EEP paid quarterly distributions of $0.925 per unit and effective November 2007, EEP increased quarterly distributions to $0.95 per unit. In the first two quarters of 2008 EEP paid quarterly distributions of $0.95 per unit and effective August 2008, EEP increased quarterly distributions to $0.99 per unit. Of the $99 million Enbridge recognized as adjusted earnings from EEP during 2009, 27% (2008–37%; 2007–40%) were GP incentive earnings while 73% (2008–63%; 2007–60%) were Enbridge's limited partner share of EEP's earnings.

Results of Operations

Adjusted earnings from EEP were $99 million for the year ended December 31, 2009 compared with $60 million for the year ended December 31, 2008. EEP adjusted earnings increased due to the Company's higher ownership interest in EEP resulting from the December 2008 Class A unit subscription; an increased contribution due to additional assets placed in service and related tariff surcharges for recent expansions; higher incentive income; and, a more favourable foreign exchange rate at which EEP's earnings are translated to Canadian dollars for presentation purposes.

Adjusted earnings from EEP were $60 million for the year ended December 31, 2008 compared with $47 million for the year ended December 31, 2007. EEP adjusted earnings increased as a result of higher incentive income and increased earnings at EEP due to higher gas and crude oil delivery volumes, tariff surcharges for recent expansions and additional revenue resulting from higher average crude oil prices associated with allowance oil. These increases were partially offset by increased operating and administrative costs and write downs of natural gas inventory to fair market value as a result of declines in the price of natural gas. Also, the Company's ownership interest in EEP increased to 27.0% in December 2008.

EEP earnings were impacted by several non-recurring or non-operating adjusting items:

- Earnings included a change in the unrealized fair value on derivative financial instruments in each period.
- Earnings for the year ended December 31, 2009 included an asset impairment loss of $12 million (net to Enbridge) related to the write-down of certain assets.
- Earnings from EEP for 2009 included a Lakehead System billing correction of $4 million (net to Enbridge) related to services provided in prior periods.
- Earnings in 2008 and 2007 included dilution gains because Enbridge did not fully participate in EEP's Class A unit offerings in May 2007 and March 2008, decreasing Enbridge's ownership interest in EEP to 14.6%. In December 2008, the Company purchased an additional US$500 million in Class A units, increasing Enbridge ownership interest in EEP to 27.0%.
- 2008 earnings included non-routine costs associated with Hurricanes Gustav and Ike as well as the write-off of certain projects cancelled due to market conditions, of which the Company's share totals $2 million.
- In 2007, EEP earnings included Enbridge's $3 million share of the gain on the sale of KPC.

ENBRIDGE ENERGY, L.P. – ALBERTA CLIPPER US

In July 2009, the Company committed to fund 66.7% of the cost to construct the United States segment of the Alberta Clipper Project. The Company will fund 66.7% of the project's equity requirements through EELP, while 66.7% of the debt funding will be made through EEP. EELP – Alberta Clipper US earnings are the Company's earnings from its investment in EELP which is undertaking the project and currently represent AEDC recognized while the project is under construction.

Results of Operations

Adjusted earnings from EELP–Alberta Clipper US were $7 million for the year ended December 31, 2009. These earnings relate to AEDC earned while the project is under construction.

Business Risks

The risks identified below are specific to EEP and EELP. General risks that affect the Company as a whole are described under *Risk Management*.

Competition

EEP's Lakehead System, the United States portion of the Enbridge System, is a major crude oil export route from the WCSB. Other existing competing carriers and pipeline proposals to ship western Canadian liquids hydrocarbons to markets in the United States represent competition for the Lakehead System. Further details on such competing projects are described within *Business Risks* under *Liquids Pipelines*. EEP's Mid-Continent system and North Dakota system also face competition from existing competing pipelines, proposed future pipelines and alternative gathering facilities available to producers or the ability of the producers to build such gathering facilities. Competition for EEP's storage facilities include large integrated oil companies and other midstream energy partnerships.

Other interstate and intrastate natural gas pipelines or their affiliates and other midstream businesses that gather, treat, process and market natural gas or NGLs represent competition to EEP's natural gas segment. The level of competition varies depending on the location of the gathering, treating and processing facilities. However, most natural gas producers and owners have alternate gathering, treating and processing facilities available to them, including competitors that are substantially larger than EEP.

Financing Risk

EEP has made and expects to continue making substantial capital expenditures for the construction and development of crude oil and natural gas infrastructure. EEP intends to finance its future capital expenditures by utilizing cash from operations, borrowings under existing credit facilities and lastly from borrowings under the US$500 million revolving credit agreement with Enbridge (see *Liquidity and Capital Resources*). EEP also expects to obtain permanent financing through the issuance of additional debt and equity securities through the capital markets, as necessary.

Supply and Demand

The profitability of EEP depends to some extent on the volume of products transported on its pipeline systems. The volume of shipments on EEP's Lakehead System depends primarily on the supply of western Canadian crude oil and the demand for crude oil in the Great Lakes and Midwest regions of the United States and eastern Canada.

EEP's natural gas gathering assets are also subject to changes in supply and demand for natural gas, NGLs and related products. Commodity prices impact the willingness of natural gas producers to invest in additional infrastructure to produce natural gas. These assets are also subject to competitive pressures from third-party and producer-owned gathering systems.

Volume Risk

A decrease in volumes transported by EEP's systems can directly and adversely affect revenues and results of operations. A decline in volumes transported can be influenced by factors beyond EEP's control including: competition, regulatory action, weather, storage levels, alternative energy sources, decreased demand, fluctuations in commodity prices, economic conditions, supply disruptions, availability of supply connected to the systems and adequacy of infrastructure to move supply into and out of the systems.

Regulation

In the United States, the interstate oil pipelines owned and operated by EEP and certain activities of EEP's intrastate natural gas pipelines are subject to regulation by the FERC or state regulators and its revenues could decrease if tariff rates were protested. While gas gathering pipelines are not currently subject to active rate regulation, proposals to more actively regulate intrastate gathering pipelines are currently being considered in certain of the states in which EEP operates. In addition, the FERC has also taken an interest in regulating gas gathering systems that connect into interstate pipelines.

Market Price Risk

EEP's gas processing business is subject to commodity price risk for natural gas and NGLs. These risks have been managed by using physical and financial contracts, fixing the prices of natural gas and NGLs. Certain of these financial contracts do not qualify for cash flow hedge accounting and EEP's earnings are exposed to associated mark-to-market valuation changes.

ENBRIDGE INCOME FUND

EIF's primary assets include a 50% interest in Alliance Pipeline Canada and the 100%-owned Enbridge Saskatchewan System, both acquired from the Company in 2003. Alliance Pipeline Canada is the Canadian portion of Alliance previously described in the Natural Gas Delivery and Services segment. The Enbridge Saskatchewan System owns and operates crude oil and liquids pipelines systems from producing fields in southern Saskatchewan and southwestern Manitoba, connecting primarily with Enbridge's mainline pipeline to the United States.

EIF also owns interests in three wind power generation projects purchased from Enbridge in October, 2006 and a business that develops and operates waste-heat power generation projects at Alliance Pipeline Canada compressor stations.

Enbridge Income Fund

Proposed Corporate Restructuring

On November 2, 2009, EIF announced that Enbridge, as administrator of EIF, recommended to the EIF Board of Trustees a proposed restructuring of EIF to take effect prior to the imposition of the specified investment flow-through entity (SIFT) Canadian tax on January 1, 2011. The proposed restructuring would involve the exchange by public unitholders of their trust units, which collectively represent a 28% economic interest in EIF, for shares of a taxable Canadian corporation to be called Enbridge Income Fund Holdings Inc. (EIFH), plus a small amount of cash. The scope of activities of EIFH would be limited to investment in EIF. A committee of independent Trustees of EIF, assisted by independent legal and financial advisors, is reviewing the administrator's recommendation in light of potential alternatives and will provide their recommendations to public unitholders. The recommended restructuring would be subject to approval by unitholders.

The Company is expected to retain its current 72% economic interest in EIF following the proposed restructuring. EIF would cease to be a SIFT and would not be subject to the SIFT tax; however, the Company would continue to be subject to corporate income tax on taxable income received from EIF. The Company is expected to remain the primary beneficiary of EIF for accounting purposes following the proposed restructuring.

Incentive and Management Fees

Enbridge receives a base annual management fee for management services provided to EIF plus incentive fees equal to 25% of annual cash distributions over $0.825 per trust unit. In 2009, the Company received incentive fees of $8 million (2008 – $5 million, 2007 – $4 million) before income taxes. The Company is the primary beneficiary of EIF through a combination of voting units and a non-voting preferred unit investment and, as such, EIF is consolidated under variable interest entity accounting rules. The preferred unit investment held by Enbridge is entitled to non-cumulative monthly distributions in an amount equal to the monthly distribution per ordinary voting unit of EIF. Management fees, incentive fees and preferred unit distributions (EIF Fees) earned by Enbridge positively impact consolidated earnings. EIF Fees received by Enbridge are subject to income taxes at corporate rates.

Results of Operations

Adjusted earnings from EIF were $45 million for the year ended December 31, 2009, compared with the prior year of $41 million. EIF adjusted earnings primarily reflected a year-over-year increase in incentive fees and preferred unit distributions, net of income taxes. In 2009, EIF declared preferred unit distributions of $1.152 per unit compared with $1.032 per unit in 2008. These distribution increases were supported primarily by increased cash flow from Phase I of the Saskatchewan System expansion completed in June 2008. Increased earnings in the year ended December 31, 2009 attributable to incentive fees and preferred unit distributions were partially offset by increased income taxes at EIF and increased corporate costs compared with 2008.

Adjusted earnings from EIF were $41 million for the year ended December 31, 2008, compared with adjusted earnings of $39 million for the year ended December 31, 2007. EIF adjusted earnings for the year ended December 31, 2008 reflected increased incentive fees and preferred unit distributions, to the extent of minority interest and net of income taxes, owing to the year-over-year increase in distributions declared by EIF. Increased earnings and distributions realized by EIF in 2008 over 2007 primarily reflect the impact of six months of operations of Phase I of the Saskatchewan System expansion completed in June 2008.

EIF earnings were impacted by a non-recurring shipper claim settlement of $1 million in 2008 and tax rate changes of $2 million in 2007. In 2007, EIF recognized future taxes within entities that will become taxable in 2011 as a result of the SIFT legislation. This future tax increase was more than offset by the revaluation of future income tax obligations previously recorded as a result of tax rate reductions in the second and fourth quarters of 2007.

Business Risks

Risks for Alliance Pipeline Canada are similar to those identified for Alliance Pipeline US in the Natural Gas Delivery and Services segment. The following risks relate to the Saskatchewan System. General risks that affect the Company as a whole are described under *Risk Management*.

Competition

The Saskatchewan System faces competition in pipeline transportation from other pipelines as well as other forms of transportation, most notably trucking. These alternative transportation options could charge rates or provide service to locations that result in greater net profit for shippers and thereby potentially reduce shipping on the Saskatchewan System or result in possible toll reductions. The Saskatchewan System manages exposure to loss of shippers by ensuring the shipping rates are competitive and by providing a high level of service. Further, the Saskatchewan System's right-of-way and expansion efforts have created a competitive advantage. The Saskatchewan System will continue to focus on increasing efficiencies through its expansion projects in order to meet its shippers' growing demand.

Regulation

EIF's 50% interest in Alliance Pipeline Canada and certain pipelines within the Saskatchewan System are subject to the actions of various regulators, including the NEB. Actions of the regulators related to tariffs, tolls and facilities impact earnings and the success of expansion projects. Delays in regulatory approvals could result in cost escalations and construction delays. Changes in regulation, including decisions by regulators on the applicable tariff structure or changes in interpretations of existing regulations by courts or regulators, could adversely affect the results of operations of EIF.

Demand for Services

Operations and tolls for the Saskatchewan Gathering and the Westspur Systems are, in general, based on volumes transported and are on terms similar to a common carrier basis with no specific on-going volume commitments. There is no assurance that shippers will continue to utilize these systems in the future or transport volumes on similar terms or at similar tolls.

Corporate

EARNINGS

(millions of Canadian dollars)	2009	2008	2007
Adjusted Corporate Loss	**(39)**	(58)	(59)
Unrealized derivative fair value gains	**207**	26	–
Unrealized foreign exchange gains on translation of intercompany balances, net	**133**	–	–
Gain on sale of investment in NTP	**25**	–	–
Impact of tax rate changes	**8**	–	31
Gain on sale of corporate aircraft	**–**	5	–
U.S. pipeline tax decision	**–**	(32)	–
Asset impairment loss	**–**	(17)	–
Earnings/Loss	**334**	(76)	(28)

Adjusted loss from Corporate was $39 million for the year ended December 31, 2009 compared with $58 million for the year ended December 31, 2008. The improvement in Corporate adjusted loss is a result of foreign exchange gains realized on hedge settlements and on residual United States dollar cash balances as the result of a stronger United States dollar, partially offset by higher operating costs, including compensation, and an increase in bank stand-by fees reflecting tighter credit markets.

Corporate loss before adjusting items was $58 million for the year ended December 31, 2008, comparable with $59 million for the year ended December 31, 2007.

Corporate costs were impacted by the following non-recurring or non-operating adjusting items:

- Earnings for the years ended December 31, 2009 and 2008 included unrealized fair value gains on the revaluation of derivative financial instruments resulting from forward risk management positions. The Company entered into foreign exchange derivative contracts in late 2008 and early 2009 to minimize the volatility of future United States dollar earnings. Additional derivative contracts used to mitigate cash flow volatility due to future interest rate fluctuations were entered into starting in the second quarter of 2009.
- Earnings for 2009 included net unrealized foreign exchange gains on the translation of foreign-denominated intercompany balances.
- On May 1, 2009, the Company sold its investment in NTP, an internet-based crude oil trading and clearing platform, for proceeds of $32 million, resulting in a gain of $25 million.
- Earnings for the year ended December 31, 2009 included an $8 million benefit related to favourable tax rate changes.
- A $5 million gain on the sale of a corporate aircraft is included in Corporate costs for the year ended December 31, 2008.
- An unfavourable court decision related to the tax basis of previously owned United States pipeline assets resulted in the recognition of a $32 million income tax expense in the year ended December 31, 2008.
- A 2008 asset impairment loss arising from the write-off of goodwill related to the Company's Ontario wind power assets, as well as a write-down of the Company's investment in NSolv, a technology development venture.
- Corporate costs for 2007 reflected a $31 million charge related to favourable legislated tax changes.

Liquidity and Capital Resources

The Company expects to utilize cash from operations, the issuance of commercial paper and credit facility draws and issuance of long-term debt to fund liabilities as they become due, finance capital expenditures and pay common share dividends. At December 31, 2009, excluding the Southern Lights project financing, the Company had $6,011 million of committed credit facilities of which $3,643 million was drawn or allocated to backstop commercial paper. At December 31, 2009, the Company has provided its affiliates EEP and EIF with liquidity support of US$500 million and $100 million, respectively, under revolving credit agreements. Drawings on the EEP and EIF facilities at December 31, 2009 were nil and $12 million, respectively. As a result, the Company had net available liquidity at December 31, 2009 of $2,024 million, inclusive of unrestricted cash and cash equivalents of $268 million. The net available liquidity is expected to be sufficient to finance all currently secured capital projects, including the investment in the United States portion of the Alberta Clipper project, and to provide flexibility for new investment opportunities.

The Company actively manages its bank funding sources to ensure adequate liquidity and optimize pricing and other terms. During the year, the following transactions occurred:

- In December 2009, the Company cancelled a credit facility and reduced an existing facility, decreasing credit facilities in Corporate by $517 million.
- Also in December 2009, EEP cancelled two credit facilities, decreasing its available credit by US$350 million.
- In July 2009, the Company secured additional committed credit facilities and amended existing credit facilities to increase total Corporate credit facilities by $70 million and decrease Natural Gas Delivery and Services credit facilities by $200 million.
- In June 2009, EIF secured additional credit facilities of $150 million of which the Company committed $100 million on the same terms as a third party bank lender. This additional credit supplements EIF's liquidity to finance its capital program and funded a debt maturity in December 2009.
- In April 2009, EEP secured additional credit facilities of US$350 million of which the Company committed US$150 million on the same terms as the third party bank lenders. This additional liquidity supplemented EEP's liquidity to manage its 2009 capital program.

On July 20, 2009, Enbridge announced that it will fund two-thirds of the estimated US$1,300 million United States segment of the Alberta Clipper Project. As a result of this investment, in December 2009, the US$350 million credit facilities were cancelled. Further, in 2009, EEP repaid an affiliate loan owing to the Company in the amount of US$130 million.

The following table provides details of the Company's credit facilities at December 31, 2009

	Expiry Dates	Total Facilities	Credit Facility Draws [2]	Available
(millions of Canadian dollars)				
Liquids Pipelines	2011	1,300	876	424
Natural Gas Delivery and Services	2010–2011	813	512	301
Corporate	2011–2013	3,898	2,255	1,643
		6,011	3,643	2,368
Southern Lights project financing [1]	2014	1,796	1,531	265
Total Credit Facilities		7,807	5,174	2,633

1 *Total facilities inclusive of $186 million which is available if certain conditions related to the project are met.*

2 *Includes facility draws and commercial paper issuances, net of discount, that are back-stopped by the credit facility.*

The Company's credit facility agreements include standard default and covenant provisions whereby accelerated repayment may be required if the Company were to default on payment or violate certain covenants. As in prior years, the Company expects to continue to comply with these provisions and therefore not trigger any early repayments. As at December 31, 2009, the Company was in compliance with all debt covenants.

The Company continues to manage its debt to capitalization ratio to maintain a strong balance sheet. The Company's debt to capitalization ratio at December 31, 2009, including short-term borrowings but excluding non-recourse debt and project financing, was 63.6%, compared with 63.6% at the end of 2008. Including all debt, the capitalization ratio was 66.1% at December 31, 2009 compared with 66.6% at December 31, 2008.

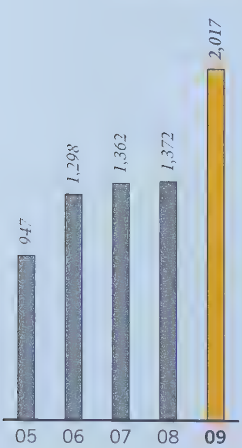
The Company invests its surplus cash in short-term investment grade instruments with credit worthy counterparties. Short-term investments were $143 million at December 31, 2009 (2008–$474 million).

Excluding current maturities of long-term debt, the Company has a positive working capital position, consistent with December 31, 2008.

(millions of Canadian dollars)	**2009**	2008
Cash and cash equivalents [1]	**327**	542
Accounts receivable and other	**2,484**	2,322
Inventory	**784**	845
Short-term borrowings	**(508)**	(874)
Accounts payable and other	**(2,463)**	(2,411)
Interest payable	**(104)**	(102)
Working capital	**520**	322

1 *Includes short-term investments.*

Changes in commodity prices impact accounts receivable and other, inventory and accounts payable and other within Energy Services and EGD.



Cash Provided by Operating Activities
(millions of Canadian dollars)

OPERATING ACTIVITIES

Cash provided by operating activities increased to $2,017 million for the year ended December 31, 2009 from $1,372 million for the year ended December 31, 2008. The increase in cash provided by operating activities in 2009 compared with 2008 resulted primarily from increased contributions from the Company's growth projects placed into service in 2009 and additional contributions from EEP as a result of the Company's increased ownership. Cash provided by operating activities for the year ended December 31, 2008 of $1,372 million is comparable to cash provided by operating activities of $1,362 million for the year ended December 31, 2007.

There are no material restrictions on the Company's cash with the exception of proportionately consolidated joint venture cash of $52 million, which cannot be accessed until distributed to the Company, and cash in trust of $7 million for specific shipper commitments.

INVESTING ACTIVITIES

In 2009, cash used for investing activities was $3,306 million compared with $2,853 million in 2008, an increase of $453 million. Additions to property, plant and equipment of $3,225 million for the year ended December 31, 2009 related primarily to capital expenditures on growth projects, most notably

Southern Lights and Alberta Clipper. Offsetting these expenditures in 2009 were proceeds on the sale of OCENSA of $535 million. In comparison, proceeds on the sale of the Company's investment in CLH were $1,383 million for the year ended December 31, 2008.

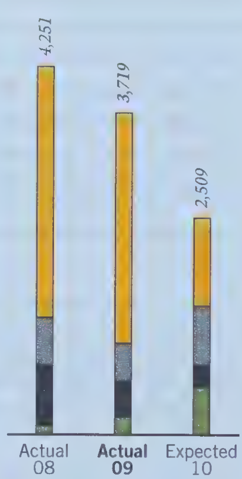
Investing activities also include long-term investments and affiliate lending. Additions to long-term investments in 2009 include $357 million related primarily to the Company's investment in EELP, which is constructing the United States segment of the Alberta Clipper Project. In 2009, the Company advanced US$270 million to EEP to fund its share of the debt component of the Alberta Clipper Project which was offset by the repayment by EEP of a US$130 million affiliate loan. In 2008, the Company increased its investment in EEP by subscribing for 16.3 million Class A common units for US$500 million.

Cash used for investing activities for the year ended December 31, 2008 was $2,853 million compared with $2,229 million in 2007. The increase was due to additional capital expenditures on growth projects and core capital maintenance expenditures in 2009 compared with 2008, as well as an additional investment in EEP in November 2008. Partially offsetting these increases was proceeds of $1,383 million on the sale of the Company's investment in CLH in June 2008.

Capital Expenditures and Investments

	Expected 2010	**Actual 2009**	Actual 2008
(millions of Canadian dollars)			
Liquids Pipelines	1,022	**2,662**	2,898
Natural Gas Delivery and Services	677	**440**	544
Sponsored Investments	258	**400**	700
Corporate	552	**217**	109
	2,509	**3,719**	4,251

The Company's capital expansion initiatives are described in *Growth Projects*. The Company also requires capital for ongoing core maintenance and capital improvements in many of its businesses. In total, Enbridge expects to spend approximately $2,509 million during 2010 on maintenance and capital projects, including equity investments in EEP and EELP (within Sponsored Investments), which are substantially secured. While consistent or still in excess of longer term historic levels, the expected decline in 2010 expenditures relative to 2009 and 2008 reflects the completion of certain large multi-year construction projects. The 2010 expected corporate capital expenditures increase reflects new green investments in wind and solar power generation. The Company expects to finance these expenditures through cash from operating activities and available liquidity. The Company may also raise capital through the monetization or disposition of selected assets, or through access to capital markets as required.



Capital Expenditures and Investments
(millions of Canadian dollars)

The decision to finance with debt or equity is based on the capital structure for each business and the overall capitalization of the consolidated enterprise. Certain of the regulated pipeline and gas distribution businesses issue long-term debt to finance capital expenditures. This external financing may be supplemented by debt or equity injections from the parent company. Debt, and equity when required, has been issued by the Company to finance business acquisitions, investments in subsidiaries and long-term investments. Funds for debt retirements are generated through cash provided from operating activities as well as through the issuance of replacement debt.

FINANCING ACTIVITIES

In 2009, the Company generated cash of $1,109 million through financing activities compared with $1,840 million and $904 million in 2008 and 2007, respectively.

Significant financing activities in 2009 include medium-term note issues of $1,500 million compared with $498 million in 2008 and $1,342 million in 2007. In 2009, the Company issued both a $400 million seven-year and 10-year term note along with a $200 million 30-year term note. Enbridge Pipelines Inc. (EPI) issued $300 million and $200 million in 10-year and 30-year term notes, respectively. In comparison, in 2008 EGD issued a $200 million five-year term note and EPI closed a $300 million 10-year term note; 2007 included the issuance of US$1,100 million in term notes issued in the United States market by the Company and $200 million of term notes issued by EGD in the Canadian market. Cash generated through debenture and term note issues is partially offset by repayments of debentures and term notes which totaled $516 million, $602 million and $635 million for the years ended December 31, 2009, 2008 and 2007, respectively.

In 2008, the Company secured financing that is non-recourse to the Company specific to the Canadian and United States segments of the Southern Lights Project. Net proceeds on Southern Lights financing were $343 million for the year ended December 31, 2009 and $1,238 million for the year ended December 31, 2008.

Short-term borrowings are used primarily to finance near term working capital requirements, including inventory at EGD. Due to the decline in natural gas commodity prices in 2009 compared with 2008, and the resultant decline in cash needed to finance inventory requirements, the Company made net repayments on short term borrowings totaling $366 million in 2009. In comparison, the net change in short-term borrowings provided cash of $329 million in 2008, and a net repayment of short-term borrowings of $262 million was made in 2007.

Participants in the Company's Dividend Reinvestment and Share Purchase Plan receive a 2% discount on the purchase of common shares with reinvested dividends. For the year ended December 31, 2009, dividends declared were $555 million (2008 – $489 million), of which $414 million (2008 – $359 million) were paid in cash and reflected in financing activities. The remaining $141 million of dividends declared were reinvested pursuant to the plan and resulted in the issuance of common shares rather than a cash payment. For the year ended December 31, 2009 and December 31, 2008, 25% and 27%, respectively, of total dividends declared were reinvested.

Outstanding Share Data [1]

	Number
Preferred Shares, Series A (non-voting equity shares)	5,000,000
Common Shares – issued and outstanding (voting equity shares)	378,351,456
Total issued and outstanding stock options (7,512,712 vested)	15,735,885

1 *Outstanding share data information is provided as at February 10, 2010.*

Contingencies and Commitments

ENBRIDGE GAS DISTRIBUTION INC.

Bloor Street Incident

EGD was charged under both the Ontario Technical Standards and Safety Act (TSSA) and the Ontario Occupational Health and Safety Act (OHSA) in connection with an explosion that occurred on Bloor Street West in Toronto in April 2003. In October 2007, all of the TSSA and OHSA charges against EGD were dismissed by the Ontario Court of Justice. The decision has been appealed by the Crown to the Ontario Superior Court of Justice and the appeal was heard by the Court during November and December 2009. The Court's decision has been reserved and EGD expects it to be released in early 2010. EGD does not believe any fines that may be levied would have a material financial impact on EGD.

EGD has also been named as a defendant in a number of civil actions related to the explosion. All significant civil actions have been settled without any material financial impact on EGD. A Coroner's Inquest in connection with the explosion is also possible.

OTHER TAX MATTERS

Enbridge and its subsidiaries maintain tax liabilities related to uncertain tax positions. While fully supportable in the Company's view, these tax positions, if challenged by tax authorities, may not be fully sustained on review.

OTHER LITIGATION

The Company and its subsidiaries are subject to various other legal and regulatory actions and proceedings which arise in the normal course of business, including interventions in regulatory proceedings and challenges to regulatory approvals and permits by special interest groups. While the final outcome of such actions and proceedings cannot be predicted with certainty, Management believes that the resolution of such actions and proceedings will not have a material impact on the Company's consolidated financial position or results of operations.

COMMITMENTS

The Company has signed contracts for the purchase of services, pipe and other materials totaling $697 million. Of this amount, $406 million is to be used in the construction of several Liquids Pipelines projects including Southern Lights Pipeline.

On July 20, 2009, the Company committed to fund 66.7% of the United States segment of the Alberta Clipper Project through EEP and EELP. The total cost of the United States segment is estimated at US$1,300 million.

CONTRACTUAL OBLIGATIONS

Payments due for contractual obligations over the next five years and thereafter are as follows:

	Total	Less than 1 year	1–3 years	3–5 years	After 5 years
(millions of Canadian dollars)					
Long-term debt [1]	12,168	600	151	1,269	10,148
Non-recourse long-term debt [1]	1,472	109	140	156	1,067
Capital and operating leases	176	18	40	35	83
Long-term contracts [2,3]	1,654	834	444	238	138
Post-employment benefit obligations [4]	74	74	–	–	–
Total Contractual Obligations	15,544	1,635	775	1,698	11,436

1 *Excludes interest. Changes to the planned funding requirements dependent on the terms of any debt re-financing agreements.*

2 *Approximately $406 million of these contracts are commitments for materials related to the construction of Liquids Pipelines projects. Changes to the planned funding requirements are dependent on changes to the related projects.*

3 *Contracts totaling $138 million are between the Company and proportionately consolidated joint venture entities.*

4 *Assumes only required payments will be made into the pension plans in 2010. Contributions are made in accordance with the independent actuarial valuations as of December 31, 2009. Contributions, including discretionary payments, may vary pending future benefit design and asset performance.*

Quarterly Financial Information [1]

2009	Q1	Q2	Q3	Q4	Total
(millions of Canadian dollars, except for per share amounts)					
Revenues	**3,783**	**2,868**	**2,629**	**3,186**	**12,466**
Earnings applicable to common shareholders	**558**	**393**	**304**	**300**	**1,555**
Earnings per common share	**1.54**	**1.08**	**0.83**	**0.81**	**4.27**
Diluted earnings per common share	**1.53**	**1.08**	**0.83**	**0.80**	**4.25**
Dividends per common share	**0.37**	**0.37**	**0.37**	**0.37**	**1.48**

2008	Q1	Q2	Q3	Q4	Total
(millions of Canadian dollars, except for per share amounts)					
Revenues	3,968	3,871	4,368	3,924	16,131
Earnings applicable to common shareholders	251	658	148	264	1,321
Earnings per common share	0.70	1.83	0.41	0.72	3.67
Diluted earnings per common share	0.70	1.81	0.41	0.71	3.64
Dividends per common share	0.33	0.33	0.33	0.33	1.32

1 *Quarterly financial information has been extracted from financial statements prepared in accordance with Canadian GAAP.*

Several factors impact comparability of the Company's financial results on a quarterly basis, including, but not limited to, seasonality in the Company's gas distribution businesses, fluctuations in market prices such as foreign exchange rates and commodity prices, disposals of investments or assets and the timing of in-service dates of new projects.

EGD and the Company's other gas distribution businesses are subject to seasonal demand. A significant portion of gas distribution customers use natural gas for space heating; therefore, volumes delivered and resultant revenues and earnings typically increase during the winter months of the first and fourth quarters of any given year. Revenues generated by EGD and other gas distribution businesses also vary from quarter-to-quarter with fluctuations in the price of natural gas, although earnings remain neutral due to the pass through nature of these costs. Further, in EGD, as a result of continued changes in customer billing to increase the fixed charge portion and decrease the per unit volumetric charge, revenues and earnings will shift from the colder winter quarters progressively to the warmer summer quarters, with no material impact on full year revenue and earnings. This change will also impact the comparability of a given quarter from year to year. In each of the four quarters of 2009, revenues generated by EGD and other gas distribution businesses have declined compared with the corresponding quarters of 2008 primarily due to depressed natural gas prices throughout 2009 compared with the prior year.

The Company actively manages its exposure to market price risks including, but not limited to, commodity prices and foreign exchange rates. To the extent derivative instruments used to manage these risks are non-qualifying for the purposes of hedge accounting, unrealized fair value gains and losses on these instruments will impact earnings. Most notably, earnings were negatively impacted by an unrealized derivative fair value loss of $43 million in the first quarter of 2009, and positively impacted by unrealized derivative fair value gains of $115 million, $102 million and $33 million for the second, third and fourth quarters of 2009, respectively. In comparison, earnings for the fourth quarter of 2008 included an unrealized derivative fair value gain of $26 million, while the first three quarters of 2008 had no similar impact. Further, second, third and fourth quarter earnings of 2009 include unrealized foreign exchange gains on translation of intercompany loans of $68 million, $50 million and $15 million, respectively, compared with nil in each of the corresponding periods of 2008.

Other significant items that impacted the quarterly results include a gain of $329 million on the disposition of the Company's investment in OCENSA in the first quarter of 2009 and a gain on sale of the Company's investment in CLH in the amount of $556 million in the second quarter of 2008.

Finally, the Company is in the midst of a substantial capital program and the timing of construction and completion of growth projects may impact the comparability of quarterly results. The Company's capital expansion initiatives, including construction commencement and in-service dates, are described in *Growth Projects.*

Related Party Transactions

All related party transactions are provided in the normal course of business and, unless otherwise noted, measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties.

EEP, an equity investee, does not have employees and uses the services of the Company for managing and operating its businesses. Vector Pipeline, a joint venture, contracts the services of Enbridge to operate the pipeline. Amounts for these services, which are charged at cost in accordance with service agreements, for the year ended December 31, 2009 are $342 million (2008 – $302 million; 2007 – $267 million) to EEP and $6 million (2008 – $6 million; 2007 – $5 million) to Vector Pipeline. At December 31, 2009, the Company has accounts receivable of $38 million (2008 – $41 million) from EEP and $1 million (2008 – $1 million) from Vector Pipeline.

The Company has provided EEP with an unsecured revolving credit agreement for general liquidity support. The credit facility provides for a maximum principle amount of US$500 million for a three-year term maturing in December 2010. At December 31, 2009 and 2008, there were no amounts outstanding on this facility.

EGD, a subsidiary of the Company, has contracts for gas transportation services from Alliance and Vector Pipeline. EGD is charged market prices for these services. For the year ended December 31, 2009, EGD was charged $42 million (2008 – $41 million; 2007 – $36 million) for services from Alliance Pipeline and $29 million (2008 – $27 million; 2007 – $25 million) from Vector Pipeline.

Enbridge Gas Services (US) Inc., a subsidiary of the Company, purchases and sells gas at prevailing market prices with Enbridge Marketing (US) Inc., a subsidiary of EEP. For the year ended December 31, 2009, amounts purchased were $16 million (2008 – $52 million; 2007 – $43 million) and sales were $6 million (2008 – $7 million; 2007 – $4 million).

Enbridge Gas Services Inc. and Enbridge Gas Services (US) Inc., subsidiaries of the Company, have transportation commitments, measured at market value, through 2015 on Alliance Pipeline Canada, Alliance Pipeline US and Vector Pipeline. For the year ended December 31, 2009, amounts paid to Alliance Pipeline Canada were $9 million (2008 – $9 million; 2007 – $8 million), amounts paid to Alliance Pipeline US were $7 million (2008 – $7 million; 2007 – $7 million) and amounts paid to Vector Pipeline were $16 million (2008 – $16 million; 2007 – $16 million).

Tidal Energy Marketing Inc., a subsidiary of the Company, purchases and sells commodities at prevailing market prices with EEP and a subsidiary of EEP. For the year ended December 31, 2009, amounts purchased were $80 million (2008 – $24 million; 2007 – $5 million) and sales were $7 million (2008 – $9 million; 2007 – $6 million).

CustomerWorks, a joint venture, provided customer care services to EGD under an agreement having a five-year term which expired in 2007 and was not renewed. EGD was charged market prices for these services. For the year ended December 31, 2009, amounts charged by CustomerWorks to EGD were nil (2008 – nil; 2007 – $26 million). CustomerWorks also rented an automated billing system from Enbridge Commercial Services Inc. (ECS), a subsidiary of the Company. For the year ended December 31, 2009, amounts charged by ECS to CustomerWorks were $2 million (2008 – $2 million; 2007 – $2 million).

ALBERTA CLIPPER PROJECT

In July 2009, the Company committed to fund 66.7% of the cost to construct the United States segment of the Alberta Clipper Project. The total cost of the United States segment, which is expected to be ready for service on April 1, 2010, is estimated at US$1,300 million, with total expenditures to date of US$900 million. Further information on this project is included in *Growth Projects.*

The Company is funding 66.7% of the project's equity requirements through EELP, an equity investee. The Company has provided a $282 million (US$270 million) loan to EEP for debt financing related to the construction. At December 31, 2009, this amount is included in Accounts Receivable and Other. The loan, denominated in United States dollars, bears interest based on variable short-term rates.

In August 2008, the Company transferred $23 million, measured at market value, of 36 inch diameter line pipe to EEP for use in constructing the United States segment of the Alberta Clipper Project.

SPEARHEAD NORTH PIPELINE

In May 2009, the Company sold a section of the Spearhead Pipeline to its affiliate EEP for proceeds of US$75 million. This related party transaction has been recorded at the exchange amount which was equal to the carrying amount.

SOUTHERN LIGHTS PROJECT

In February 2009, as part of its Southern Lights Pipeline Project, the Company transferred the United States section of a newly constructed light sour pipeline to EEP in exchange for a pipeline referred to as Line 13. This non-monetary transaction has been recorded at the carrying amount.

In connection with the exchange discussed above, EEP entered into an arrangement to lease Line 13 from the Company for monthly payments of US$2 million to ensure adequate southbound pipeline capacity prior to the completion of the Alberta Clipper Project. The lease arrangement was effective in February 2009 and can be terminated at any time with written notice.

LONG-TERM RECEIVABLE FROM AFFILIATE

The affiliate long-term note receivable of $159 million (US$130 million) as at December 31, 2008, included in Deferred Amounts and Other Assets, was repaid by EEP in November 2009. Interest income for the year ended December 31, 2009 related to the note receivable was $11 million (2008 – $12 million; 2007 – $10 million).

Risk Management

Enbridge's value proposition is based on maintaining a very low risk profile. Over 85% of the Company's earnings come from regulated businesses; over 80% of its revenues are volume protected under cost of service rate-making or long-term take-or-pay arrangements; and more than 95% of the Company's revenues come from investment grade customers. Other risks, such as capital cost and inflation, are generally transferred to customers through contractual arrangements. In addition to contractually eliminating the majority of its business risk, the Company has formal risk management policies, procedures and systems designed to mitigate any residual risks, such as market price risk, credit risk and operational risk. In addition, the Company performs an annual corporate risk assessment to scan its environment for all potential risks. Risks are ranked based on severity and likelihood and results are considered in the Company's strategic and operating plans. Through this process, a range of ongoing mitigants are identified and implemented.

MARKET PRICE RISK

The Company's earnings, cash flows and other comprehensive income (OCI) are subject to movements in foreign exchange rates, interest rates and commodity prices (collectively, market price risk). Given the Company's desire to maintain a stable and consistent earnings profile, it has implemented a Market Price Risk Management Policy which outlines a risk management governance framework and specific exposure limits to minimize the likelihood that adverse earnings fluctuations arising from movements in market prices across all of its businesses will exceed a defined tolerance.

Earnings at Risk (EaR), a variant of Value at Risk, is the principal risk management metric used to quantify market price risk sensitivity at Enbridge. EaR is an objective, statistically derived risk metric that measures the maximum adverse change in projected 12-month earnings that could result from market price risk over a one-month period within a 97.5% confidence interval. The philosophy behind this metric is to identify the potential risk to the Company's annual earnings target, taking into account the illiquidity of certain exposure positions. The Company's policy is to limit EaR to a maximum of 5% of the next 12 months of forecasted earnings. Earnings exposure to market price risk is managed within the overall consolidated EaR limits of the Company. Further, commodity price risk is managed within business unit EaR sub-limits.

Various hedging programs have been put into place to help ensure that the residual market price risks remain within policy limits, and thus help provide the Company with a general stability of earnings over a short and medium term horizon. The following section summarizes the primary types of market price risks to which the Company is exposed, and outlines the financial derivative hedging programs implemented.

Foreign Exchange Risk

The Company's earnings, cash flows and OCI are subject to foreign exchange rate variability, primarily arising from the performance of its United States dollar denominated subsidiaries. The Company has implemented a policy where it must hedge a minimum level of foreign currency denominated earnings exposures identified over the next five year period. The Company currently has hedged over 80% of its forecast adjusted earnings through 2014 at an average rate of approximately $1.20 C$/US$. The Company may also hedge anticipated foreign currency denominated purchases or sales, foreign currency denominated debt, as well as certain equity investment balances and net investments in foreign denominated subsidiaries.

Interest Rate Risk

The Company's earnings and cash flows are exposed to short term interest rate variability due to the regular repricing of its variable rate debt obligations. Floating to fixed interest rate swaps and options are used to hedge against the effect of future period interest rate movements. The Company has implemented a hedging program to significantly mitigate the volatility to variable rate interest expense through 2013 at an average rate of 2.2%.

The Company's earnings and cash flows are also exposed to variability in longer term interest rates on future fixed rate debt issuances. Forward starting interest rate swaps are used to hedge against the effect of future interest rate movements. The Company has implemented a hedging program to significantly mitigate its exposure to long term interest rate variability on select forecast term debt issuances through 2013. A total of $2,500 million of future fixed rate term debt issuances have been hedged at an average government bond rate of 4%. Further, many of the Company's existing commercial arrangements and certain construction projects provide for the full recovery of financing costs through tolls.

The Company also monitors its debt portfolio mix of fixed and variable rate debt instruments to ensure that the consolidated portfolio of debt stays within its Board of Directors, approved policy limit band of a maximum of 25% floating rate debt as a percentage of total debt outstanding.

Commodity Price Risk

The Company's earnings and cash flows are exposed to changes in commodity prices as a result of ownership interest in certain assets, as well as through the activities of its energy services subsidiaries. The Company uses natural gas, power, crude oil and NGL derivative instruments to fix a portion of the variable price exposures that may arise from commodity usage, storage, transportation and supply agreements.

The Company has implemented a hedging program, through 2011, to mitigate the volatility from fractionation spreads (natural gas/NGLs) that impact earnings from its ownership in the Aux Sable natural gas processing plant.

The following table summarizes the EaR as a percentage of forecast earnings from the main groups of market price risk after the impact of the Company's hedging programs. These EaR numbers are based on business conditions and hedging programs as of December 31, 2009 and may not be applicable to other periods.

Risk	EaR
(% of forecast 12 month forward earnings)	
Foreign Exchange	0.3%
Interest Rate	–%
Commodity	2.3%
Total	2.6%

CREDIT RISK

The Company's earnings and cash flows could be exposed to the risk of payment default by its shippers or other counterparties. Given the Company's desire to maintain a stable and consistent earnings profile, it has implemented a Counterparty Credit Risk Policy outlining a governance framework and specific exposure limits to minimize the likelihood that adverse earnings fluctuations arise from counterparty defaults across any of its businesses.

Further initiatives to mitigate credit exposure include ensuring that all counterparties shipping on the regulated oil pipelines that have credit ratings below investment grade provide the carrier with a form of credit assurance, for example, a creditworthy parental guarantee, letter of credit or cash.

Credit risk in the Natural Gas Delivery and Services segment is mitigated by its large and diversified customer base and its ability to recover an estimate for doubtful accounts through the ratemaking process. The Company actively monitors the financial strength of large industrial customers and, in select cases, has tightened credit terms, including obtaining additional security, to minimize the consequences of the risk of default on receivables. Generally, the Company classifies receivables older than 30 days as past due.

The Company minimizes credit risk to derivatives counterparties by entering into risk management transactions only with institutions that possess solid investment grade credit ratings or which have provided the Company with an acceptable form of credit protection. The Company has no significant concentration with any single counterparty. During 2008, the Company reduced its exposure to certain financial counterparties through the discontinuance of certain hedges. For transactions with terms greater than five years, the Company may also require a counterparty that would otherwise meet the Company's credit criteria to provide collateral. During 2009, despite the severe market conditions, the Company did not suffer any material credit losses.

FINANCING RISK

The Company's financing risk relates to the price volatility and availability of debt to finance organic growth projects and refinance existing debt maturities. This risk is directly influenced by market factors, as Canadian and United States financial market conditions can change dramatically, affecting capital availability.

To address this risk, the Company maintains sufficient liquidity through committed credit facilities with its diversified banking groups designed to enable the Company to fund all anticipated requirements for one year without accessing the capital markets. In addition, the Company strives to ensure that it can readily access the Canadian and United States public capital markets by maintaining current shelf prospectuses with the securities regulators.

LIQUIDITY RISK

Liquidity risk is the risk that the Company will not be able to meet its financial obligations, including commitments and guarantees. To manage this risk, the Company forecasts the cash requirements over the near and long term to determine whether sufficient funds will be available. The Company's primary sources of liquidity and capital resources are funds generated from operations, the issuance of commercial paper and draws under committed credit facilities, as well as medium-term notes. The Company maintains current shelf prospectuses with the securities regulators, which enables, subject to market conditions, ready access to either the Canadian or United States public capital markets.

MATURITIES OF DERIVATIVE FINANCIAL LIABILITIES

For the years ending December 31, 2010 through 2014, and thereafter, the Company has estimated the following undiscounted cash flows will arise from its derivative instruments based on valuation at the balance sheet date.

(millions of Canadian dollars)	2010	2011	2012	2013	2014	Thereafter
Cash inflows	182	106	136	155	86	51
Cash outflows	(167)	(29)	(5)	(7)	(3)	(25)
Net cash flows	15	77	131	148	83	26

The maturity profile of non-derivative financial liabilities is presented in *Liquidity and Capital Resources.*

GENERAL BUSINESS RISKS

Execution Risk

The Company's ability to successfully execute the development of its organic growth projects may be influenced by capital constraints, third-party opposition, changes in shipper support over time, delays in or changes to government and regulatory approvals, cost escalations, construction delays, shortages and in-service delays (collectively, Execution Risk). The Company's growth plans may strain its resources and may be subject to high cost pressures in the North American energy sector. Early stage project risks include right-of-way procurement, special interest group opposition, Crown consultation, and environmental and regulatory permitting. Cost escalations may impact project economics. Construction delays due to slow delivery of materials, contractor non-performance, weather conditions and shortages may impact project development. Labour shortages, inexperience and productivity issues may also affect the successful completion of the projects.

The Company has a centralized and clearly defined governance structure and process for all major projects with dedicated resources organized to lead and execute each major project. Capital constraints and cost escalation risks are mitigated through structuring of commercial agreements, typically where shippers retain complete or a share of capital cost excess. The Company's emphasis on corporate social responsibility promotes generally positive relationships with landowners, aboriginal groups and governments which help to facilitate right-of-way acquisition, permitting and schedule. Detailed cost tracking and centralized purchasing

is used on all major projects to facilitate optimum pricing and service terms. Strategic relationships have been developed with suppliers and contractors. Compensation programs, communications and the working environment are aligned to attract, develop and retain qualified personnel.

Pipeline Operating Risk

Pipeline leaks are an inherent risk of operations. Other operating risks include: the breakdown or failure of equipment, information systems or processes; the performance of equipment at levels below those originally intended (whether due to misuse, unexpected degradation or design, construction or manufacturing defects); failure to maintain adequate supplies of spare parts; operator error; labour disputes; disputes with interconnected facilities and carriers; and catastrophic events such as natural disasters, fires, explosions, fractures, acts of terrorists and saboteurs and other similar events, many of which are beyond the control of the pipeline systems. The occurrence or continuance of any of these events could increase the cost of operating the Company's pipelines or reduce revenues, thereby impacting earnings.

The Company has an extensive program to manage system integrity, which includes the development and use of in-line inspection tools. Maintenance, excavation and repair programs are directed to the areas of greatest benefit and pipe is replaced or repaired as required. The Company also maintains comprehensive insurance coverage for significant pipeline leaks and has a comprehensive security program designed to reduce security-related risks. While the Company feels the level of insurance is adequate, it may not be sufficient to cover all potential losses.

Regulation

Many of the Company's pipeline operations are regulated and are subject to regulatory risk. The nature and degree of regulation and legislation affecting energy companies in Canada and the United States has changed significantly in past years and there is no assurance that further substantial changes will not occur. These changes may adversely affect toll structures or other aspects of pipeline operations or the operations of shippers. Recently shippers have challenged toll increases on various pipelines owned by some of Enbridge's competitors, and certain of Enbridge's shippers have sought to delay the in-service date and implementation of the tariff on the Company's Alberta Clipper Project. Enbridge retains dedicated professional staff and maintains strong relationships with customers, interveners and regulators to help minimize regulatory risk.

Environmental, Health and Safety Risk

The Company's operations, facilities and petroleum product shipments are subject to extensive national, regional and local environmental, health and safety laws and regulations governing, among other things, discharges to air, land and water, the handling and storage of petroleum compounds and hazardous materials, waste disposal, the protection of employee health, safety and the environment, and the investigation and remediation of contamination. The Company's facilities could experience incidents, malfunctions or other unplanned events that result in spills or emissions in excess of permitted levels and result in personal injury, fines, penalties or other sanctions and property damage. The Company could also incur liability in the future for environmental contamination associated with past and present activities and properties. The facilities and pipelines must maintain a number of environmental and other permits from various governmental authorities in order to operate and these facilities are subject to inspection from time to time. Failure to maintain compliance with these requirements could result in operational interruptions, fines or penalties, or the need to install potentially costly pollution control technology. Compliance with current and future environmental laws and regulations, which are likely to become more stringent over time, including those governing GHG emissions, may impose additional capital costs and financial expenditures and affect the demand for the Company's services, which could adversely affect operating results and profitability. Restrictions on other resources, such as water or electricity, may affect the Company's upstream customers' ability to produce crude oil and natural gas. The Company could be targeted, along with the oil sands industry, by environmental groups attempting to draw attention to GHG emissions.

Enbridge is committed to protecting the health and safety of employees, contractors and the general public, and to sound environmental stewardship. The Company believes that prevention of incidents and injuries, and protection of the environment, benefits everyone and delivers increased value to shareholders, customers and employees. Enbridge has health and safety and environmental management systems and has established policies, programs and practices for conducting safe and environmentally sound operations. Regular reviews and audits are conducted to assess compliance with legislation and Company policy.

Aboriginal Relations

Canadian judicial decisions have recognized that Aboriginal rights and treaty rights exist in proximity to the Company's operations and future project developments. The courts have also confirmed that the Crown has a duty to consult with Aboriginal peoples when its decisions or actions may adversely affect Aboriginal rights and interests or treaty rights. Crown consultation has the potential to delay regulatory approval processes and construction, which may affect project economics. In some cases, respecting Aboriginal rights may mean regulatory approval is denied or made economically challenging.

Given this environment and the breadth of relationships across the Company's geographic span, Enbridge has recently reviewed and updated its Indigenous Peoples Policy, which has been renamed the Aboriginal and Native American Policy. The new Policy promotes the achievement of participative and mutually beneficial relationships with Aboriginal and Native American groups affected by the Company's projects and operations. Specifically, the Policy sets out principles governing the Company's relationships with Aboriginal and Native American peoples and makes commitments to work with Aboriginal peoples and Native Americans so they may realize benefits from the Company's projects and operations. Notwithstanding the Company's efforts to this end, the issues are complex and the impact of Aboriginal relations on Enbridge's operations and development initiatives is uncertain.

Special Interest Groups

The Company is exposed to the risk of higher costs, delays or even project cancellations due to increasing pressure on government and regulators by special interest groups. Recent Supreme Court decisions have increased the ability of special interest groups to make claims and oppose projects in regulatory and legal forums. The Company works proactively with special interest groups to identify and develop an appropriate response to concerns regarding its projects. The Company's Corporate Social Responsibility (CSR) program also reports on the Company's responsiveness to environmental and community issues. Please see Enbridge's annual CSR report, available online at www.enbridge.com/csr2009 for further details regarding the CSR program.

Legislation Risk

Climate Change Legislation

The Canadian Federal Government has indicated that Canada will target a 17% reduction of GHG emissions by 2020, based on 2006 emission levels. It has also signaled that 90% of Canada's electricity will be provided by non-emitting sources, such as hydro, nuclear, clean-coal, solar and wind, by 2020. Details of Canada's GHG management plan will not be released until there is clarity in the United States about its intention to regulate GHG emissions. Canadian regulations will likely be compatible with those of the United States in order for Canadian businesses to remain competitive and avoid the potential for punitive trade sanctions. It is uncertain how climate legislation could affect the industry. Enbridge continues to monitor this activity.

Low Carbon Fuel Standards

California and Oregon have adopted Low Carbon Fuel Standards and other states (including the seven New England states) are considering the same. If widely adopted, such standards could limit United States refiners from importing oil sands products, as they are more energy-intensive to process than conventional crude. Flow restrictions of oil sands products to the United States would increase interest in exports to Asia, and consequently increase interest in projects like Enbridge's Northern Gateway Project.

Renewable Energy

Enbridge has significant interest in wind and solar power and is well positioned to expand this portfolio. Many programs to encourage and advance renewable energy exist in Canada and the United States as well as individual provinces and states. For example, the Feed-in-Tariff program introduced by the Ontario Green Energy Act has created significant opportunities for renewable energy growth in Ontario. The extension of the Production Tax Credit, introduction of a federal cash grant and the potential for a nationwide minimum Renewable Portfolio Standard have accelerated renewable energy projects across the United States. Enbridge continues to assess and advance renewable energy opportunities and monitor potential changes to government policies and incentives that may positively or negatively impact renewable energy projects in a particular province, state or federal jurisdiction.

Workforce Development

A lack of qualified and properly trained technical, professional and operational staff and leaders would increase the risk that the Company will not be able to implement its corporate strategy. This risk may be compounded by the increasing rates of retirement due to workforce demographics, turnover due to competition in certain markets and growing demand for staff to support business growth. The Company continues to monitor company-wide workforce planning. The Company offers competitive compensation programs, training, leadership development and succession planning. Further, the supply of human resources is balanced between hiring full-time employees and expanding the contractor workforce, particularly in the Major Projects' department.

Terrorism

The risk of terrorism continues to be monitored due to the high profile of the petroleum industry in Canada and the reliance of the United States on Canadian exports. An act of terrorism may result in the loss of upstream supplies, pipelines, distribution or storage controls systems with safety and environmental implications. The Company manages this risk through its Human Resources Protection Program, Crisis Management Plan and insurance programs where available.

Financial Instruments

December 31, 2009	Held for Trading	Available for Sale	Loans and Receivables	Held to Maturity	Other Financial Liabilities	Qualifying Derivatives	Non-Financial Instruments	Total	Fair Value [1]
(millions of Canadian dollars)									
Assets									
Cash and cash equivalents	327	–	–	–	–	–	–	327	327
Accounts receivable and other	76	–	2,054	–	–	52	302	2,484	2,182
Long-term investments	–	54	6	181	–	–	2,071	2,312	187
Deferred amounts and other assets	288	–	–	–	–	197	1,940	2,425	485
Liabilities									
Short-term borrowings	–	–	–	–	508	–	–	508	508
Accounts payable and other	36	–	–	–	2,177	87	163	2,463	2,300
Interest payable	–	–	–	–	104	–	–	104	104
Long-term debt	–	–	–	–	12,283	–	(101)	12,182	13,450
Non-recourse long-term debt	–	–	–	–	1,515	–	(9)	1,506	1,573
Other long-term liabilities	2	–	–	–	–	40	1,165	1,207	42

December 31, 2008	Held for Trading	Available for Sale	Loans and Receivables	Held to Maturity	Other Financial Liabilities	Qualifying Derivatives	Non-Financial Instruments	Total	Fair Value [1]
(millions of Canadian dollars)									
Assets									
Cash and cash equivalents	542	–	–	–	–	–	–	542	542
Accounts receivable and other	41	–	1,869	–	–	31	381	2,322	1,948
Long-term investments	–	54	167	405	–	–	1,866	2,492	492
Deferred amounts and other assets	68	-	–	–	–	249	1,001	1,318	317
Liabilities									
Short-term borrowings	–	–	–	–	874	–	–	874	874
Accounts payable and other	18	–	–	–	1,965	32	396	2,411	2,015
Interest payable	–	–	–	–	102	–	–	102	102
Long-term debt	–	–	–	–	10,795	–	(106)	10,689	11,173
Non-recourse long-term debt	–	–	–	–	1,669	–	(10)	1,659	1,672
Other long-term liabilities	11	–	–	–	–	36	212	259	47

1 *Fair value does not include non-financial instruments, which includes investments accounted for under the equity method, and available for sale equity instruments held at cost that do not trade on an actively quoted market.*

FAIR VALUE OF FINANCIAL INSTRUMENTS

The fair value of financial instruments reflects the Company's best estimates of market value based on generally accepted valuation techniques or models and supported by observable market prices and rates. When such prices are not available, the Company uses discounted cash flow analysis from applicable yield curves based on observable market inputs. The fair value of financial instruments, other than derivatives, represents the amounts that would have been received from or paid to counterparties to settle these instruments at the reporting date.

The fair value of cash and cash equivalents and short-term borrowings approximates their carrying value due to their short-term maturities. The fair value of the Company's long-term investments, other than those classified as available for sale, approximates their carrying value due to the nature of the investments. The fair value of the Company's long-term debt and non-recourse long-term debt is based on quoted market prices for instruments of similar yield, credit risk and tenure. The fair value of other financial assets and liabilities other than derivative instruments approximate their cost due to the short period to maturity. Changes in the fair value of financial liabilities other than derivative instruments are due primarily to fluctuations in interest rates and time value.

DERIVATIVE INSTRUMENTS

The following table summarizes the maturity and total notional principal or quantity outstanding related to the Company's derivative instruments. The Company does not have any credit-risk related contingent features associated with its derivative instruments.

	December 31, 2009		December 31, 2008	
	Maturity	Notional Principal or Quantity Outstanding	Maturity	Notional Principal or Quantity Outstanding
U.S. dollar cross currency swaps *(millions of Canadian dollars)*		**–**	2013–2022	138
U.S. dollar forwards – purchase *(millions of United States dollars)*	**2010–2019**	**1,078**	2009–2017	1,118
U.S. dollar forwards – sell *(millions of United States dollars)*	**2010–2020**	**3,102**	2009–2021	2,548
Interest rate contracts *(millions of Canadian dollars)*	**2010–2029**	**6,022**	2009–2029	1,164
Energy commodity *(bcf)*	**2010–2011**	**464**	2009–2010	530
Power commodity *(MW/H)*	**2010–2024**	**38**	2009–2024	57

DERIVATIVE INSTRUMENTS

December 31, 2009	Derivative Instruments used as Cash Flow Hedges	Derivative Instruments used as Net Investment Hedges	Non-Qualifying Derivative Instruments	Total Derivative Instruments
(millions of Canadian dollars)				
Accounts receivable and other				
U.S. dollar forwards	4	14	52	70
Interest rate contracts	34	–	2	36
Energy commodity	–	–	19	19
Power commodity	–	–	3	3
	38	14	76	128
Deferred amounts and other				
U.S. dollar forwards	25	80	285	390
Interest rate contracts	90	–	–	90
Energy commodity	–	–	1	1
Power commodity	1	–	1	2
Other	1	–	1	2
	117	80	288	485
Accounts payable and other				
U.S. dollar forwards	(2)	–	(3)	(5)
Interest rate contracts	(68)	–	–	(68)
Energy commodity	(17)	–	(32)	(49)
Power commodity	–	–	(1)	(1)
	(87)	–	(36)	(123)
Other long-term liabilities				
U.S. dollar forwards	(21)	–	–	(21)
Interest rate contracts	(15)	–	–	(15)
Energy commodity	(4)	–	–	(4)
Power commodity	–	–	(2)	(2)
	(40)	–	(2)	(42)
Total net derivative asset/(liability)				
U.S. dollar forwards	6	94	334	434
Interest rate contracts	41	–	2	43
Energy commodity	(21)	–	(12)	(33)
Power commodity	1	–	1	2
Other	1	–	1	2
	28	94	326	448

December 31, 2008	Derivative Instruments used as Cash Flow Hedges	Derivative Instruments used as Net Investment Hedges	Non-Qualifying Derivative Instruments	Total Derivative Instruments
(millions of Canadian dollars)				
Accounts receivable and other				
U.S. dollar forwards	12	8	–	20
Interest rate contracts	1	–	–	1
Energy commodity	9	–	32	41
Power commodity	1	–	9	10
	23	8	41	72
Deferred amounts and other				
U.S. dollar cross currency swaps	26	–	–	26
U.S. dollar forwards	153	63	56	272
Power commodity	7	–	12	19
	186	63	68	317
Accounts payable and other				
U.S. dollar forwards	–	–	(14)	(14)
Interest rate contracts	(9)	–	–	(9)
Energy commodity	(22)	–	(4)	(26)
Power commodity	(1)	–	–	(1)
	(32)	–	(18)	(50)
Other long-term liabilities				
U.S. dollar forwards	–	–	(8)	(8)
Interest rate contracts	(12)	–	–	(22)
Power commodity	(11)	–	(1)	(12)
Other	(3)	–	(2)	(5)
	(36)	–	(11)	(47)
Total net derivative asset/(liability)				
U.S. dollar cross currency swaps	26	–	–	26
U.S. dollar forwards	165	71	34	270
Interest rate contracts	(30)	–	–	(30)
Energy commodity	(13)	–	28	15
Power commodity	(4)	–	20	16
Other	(3)	–	(2)	(5)
	141	71	80	292

The fair value of derivative instruments has been estimated using period end market information. This market information includes observable inputs such as published market prices for commodities, interest rate yield curves and foreign exchange rates. When possible, financial instruments are valued using quoted market prices.

An unrealized fair value loss of $53 million (2008 – $298 million) related to derivative instruments used as cash flow and net investment hedges was recognized in OCI for the year ended December 31, 2009. An unrealized fair value gain related to non-qualifying derivative instruments of $146 million (2008 – $157 million) was recognized in commodity costs, other investment income and interest expense for the year ended December 31, 2009.

Additional information about the Company's Risk Management and Financial Instruments is included in Notes 23 and 24 of the 2009 Annual Consolidated Financial Statements.

Critical Accounting Estimates

DEPRECIATION

Depreciation of property, plant and equipment, the Company's largest asset with a net book value at December 31, 2009 of $18,850 million, or 67% of total assets, is generally provided on a straight-line basis over the estimated service lives of the assets commencing when the asset is placed in service. When it is determined that the estimated service life of an asset no longer reflects the expected remaining period of benefit, prospective changes are made to the estimated service life. Estimates of useful lives are based on third party engineering studies, experience and/or industry practice. There are a number of assumptions inherent in estimating the service lives of the Company's assets including the level of development, exploration, drilling, reserves and production of crude oil and natural gas in the supply areas served by the Company's pipelines as well as the demand for crude oil and natural gas and the integrity of the Company's systems. Changes in these assumptions could result in adjustments to the estimated service lives, which could result in material changes to depreciation expense in future periods in any of the Company's business segments. For certain rate regulated operations, depreciation rates are approved by the regulator and the regulator may require periodic studies or technical updates on useful lives which may change depreciation rates.

REGULATORY ASSETS AND LIABILITIES

Certain of the Company's Liquids Pipelines and Natural Gas Delivery and Services businesses are subject to regulation by various authorities, including but not limited to, the NEB, the FERC, the Energy Resources Conservation Board (ERCB) and the OEB. Regulatory bodies exercise statutory authority over matters such as construction, rates and ratemaking, and agreements with customers. To recognize the economic effects of the actions of the regulator, the timing of recognition of certain revenues and expenses in operations may differ from that otherwise expected under GAAP for non rate-regulated entities. Also, the Company records regulatory assets and liabilities to recognize the economic effects of the actions of the regulator. Regulatory assets represent amounts that are expected to be recovered from customers in future periods through rates. Regulatory liabilities represent amounts that are expected to be refunded to customers in future periods through rates. On refund or recovery of this difference, no earnings impact is recorded. Effectively, the income statement captures only the approved costs and the related revenue rather than the actual costs and related revenue. As of December 31, 2009, the Company's regulatory assets totaled $1,411 million (2008 – $635 million) and regulatory liabilities totaled $1,038 million (2008 – $109 million). To the extent that the regulator's actions differ from the Company's expectations, the timing and amount of recovery or settlement of regulatory balances could differ significantly from those recorded.

POST EMPLOYMENT BENEFITS

The Company maintains pension plans, which provide defined benefit and/or defined contribution pension benefits and other post-employment benefits (OPEB) to eligible retirees. Pension costs and obligations for the defined benefit pension plans are determined using the projected benefit method. This method involves complex actuarial calculations using several assumptions including discount rates, expected rates of return on plan assets, health-care cost trend rates, projected salary increases, retirement age, mortality and termination rates. These assumptions are determined by management and are reviewed annually by the Company's actuaries. Actual results that differ from assumptions are amortized over future periods and therefore could materially affect the expense recognized and the recorded obligation in future periods. The Company remains able to pay the current benefit obligations using cash from operations reflecting strong capital market performance recovery. The shortfall from expected return on plan assets was $24 million for the year ended December 31, 2009 (2008 – $288 million) as disclosed in Note 27 to the 2009 Annual Consolidated Financial Statements. The difference between the actual and expected return on plan assets is amortized over the remaining service period of the active employees.

Assuming no discretionary funding is made into the pension plans, funding in 2010 will be approximately $74 million, which is not considered significant to the Company.

The following sensitivity analysis identifies the impact on the December 31, 2009 Consolidated Financial Statements of a 0.5% change in key pension and OPEB assumptions.

	Pension Benefits		OPEB	
	Obligation	Expense	Obligation	Expense
(millions of Canadian dollars)				
Decrease in discount rate	72	10	13	1
Decrease in expected return on assets	n/a	5	n/a	–
Decrease in rate of salary increase	(17)	(5)	–	–

CONTINGENT LIABILITIES

Provisions for claims filed against the Company are determined on a case by case basis. Case estimates are reviewed on a regular basis and are updated as new information is received. The process of evaluating claims involves the use of estimates and a high degree of management judgment. Claims outstanding, the final determination of which could have a material impact on the financial results of the Company and certain of the Company's subsidiaries and investments, including EGD and EECI, are detailed in the Commitments and Contingencies section of this report and are disclosed in Note 31 of the 2009 Annual Consolidated Financial Statements.

ASSET RETIREMENT OBLIGATIONS

In May 2009, the NEB released a report on the financial issues associated with pipeline abandonment. The NEB will require all companies to formally assess the timeline and cost of future abandonment and, if necessary, set aside funds to cover future abandonment costs. All pipelines regulated under the NEB Act will be required to comply with the report's framework and action plan. The NEB began hosting technical meetings in September 2009 to evaluate how abandonment estimates will be calculated and submitted, as well as proposals for how funds will be collected and set aside. The NEB's goal is for companies, as required, to begin setting aside funds for abandonment no later than the end of May 2014. Currently, for certain of the Company's assets, it is not practical to make a reasonable estimate of asset retirement obligations for accounting purposes due to the indeterminate timing and the scope of asset retirements. However, should the NEB action plan result in a reasonable estimate of asset retirement obligations for accounting purposes, financial statement recognition of those obligations may be made in future periods. As a result, regulatory assets and liabilities may be recognized to the extent the timing of recovery from shippers differs from the recognition of abandonment costs for accounting purposes.

Change in Accounting Policies

ACCOUNTING FOR THE EFFECTS OF RATE REGULATION

Effective January 1, 2009, the Company adopted revisions to the Canadian Institute of Chartered Accountants (CICA) Handbook Section 1100, *Generally Accepted Accounting Principles* and Section 3465, *Income Taxes.* In accordance with the transitional provisions in these revised standards, the revisions to Section 1100 were adopted prospectively and, accordingly, prior periods were not restated, while the revisions to Section 3465 were applied retrospectively without restatement of prior periods. The adoption of the revised standards did not impact the Company's earnings or cash flows.

Generally Accepted Accounting Principles

The revised standard no longer provides an exemption for rate-regulated entities to measure assets and liabilities on a basis other than in accordance with primary sources of Canadian GAAP. As a result, for the pension plans and OPEB included in EGD, the Company recognized post-employment benefit assets and liabilities for the amount of benefits expected to be included in future rates and recovered from, or paid to, customers. In addition, the Company reclassified certain EGD reserves for future removal and site restoration.

Pension Plans and OPEB

On adoption of the revised standard at January 1, 2009, the Company recognized a net pension asset of $157 million and a net OPEB liability of $75 million, with an offsetting long-term net pension regulatory liability and long-term net OPEB regulatory asset, respectively. At December 31, 2009, the Company had a net pension asset of $140 million and a net OPEB liability of $80 million, with an offsetting long-term net pension regulatory liability and a long-term net OPEB regulatory asset, respectively.

Future Removal and Site Restoration Reserves

At January 1, 2009, on adoption of the revised standard, the Company reclassified amounts collected for future removal and site restoration of $657 million, which were previously netted against Property, Plant and Equipment, to a long-term regulatory liability. At December 31, 2009, this long-term regulatory liability was $710 million.

Income Taxes

The revised standard removes the exemption for rate-regulated entities to recognize future income taxes to the extent they were expected to be included in regulator-approved future rates and recovered from or refunded to future customers. As a result, on January 1, 2009, the Company recognized a future income tax liability of $816 million on regulatory assets, primarily property, plant and equipment, with an offsetting long-term regulatory asset. A regulatory asset has been recognized as the associated future income tax liability is expected to be recoverable in future rates. At December 31, 2009, the Company had a future income tax liability of $829 million related to regulatory assets with an offsetting long-term regulatory asset.

INTANGIBLE ASSETS

Effective January 1, 2009, the Company adopted CICA Handbook Section 3064, *Goodwill and Intangible Assets*, which establishes standards for the recognition, measurement, presentation and disclosure of goodwill and intangible assets. As a result of adopting this standard, the Company reclassified certain software costs from Property, Plant and Equipment to Intangible Assets. This standard has been applied retrospectively and affects presentation only.

As a result of adopting this standard, on January 1, 2009, the Company reclassified $233 million of net software costs from Property, Plant and Equipment to Intangible Assets. At December 31, 2009, the Company had $289 million of net software costs recorded in Intangible Assets.

COMMODITY INVENTORY

Effective January 1, 2009, the Company changed its accounting policy for inventory held by its energy marketing businesses and began measuring commodity inventory at fair value, as measured at the spot price less costs to sell, rather than lower of cost or net realizable value. This measurement basis is a more relevant measurement for commodity inventory used for marketing purposes and better matches the commodity inventory with the derivatives used to "lock in" the margin. This change in accounting policy has been accounted for retrospectively and did not result in restatements of the comparative Consolidated Statements of Earnings, Comprehensive Income, Shareholders' Equity or Cash Flows for the years ended December 31, 2008 and 2007 and the comparative Consolidated Statement of Financial Position as at December 31, 2008 as the amounts were considered immaterial.

INVENTORIES

The CICA issued Handbook Section 3031, *Inventories*, effective January 1, 2008 which aligns accounting for inventories under Canadian GAAP with International Financial Reporting Standards (IFRS) and replaces Section 3030. The adoption of the revised standard did not have a significant effect on the Company.

CAPITAL DISCLOSURES AND FINANCIAL INSTRUMENTS–DISCLOSURES AND PRESENTATION

Effective January 1, 2008, the Company adopted new standards for *Capital Disclosures* (CICA Handbook Section 1535) and *Financial Instruments – Disclosures and Presentation* (CICA Handbook Sections 3862 and 3863). While the new standards did not change the Company's accounting policies, they resulted in additional disclosures.

FINANCIAL INSTRUMENTS, COMPREHENSIVE INCOME AND HEDGING RELATIONSHIPS

Effective January 1, 2007, the Company adopted CICA Handbook Section 1530, *Comprehensive Income*, Section 3251, *Equity*, Section 3855, *Financial Instruments – Recognition and Measurement*, Section 3861, *Financial Instruments – Disclosure and Presentation* (subsequently replaced by Sections 3862 and 3863 adopted by the Company on January 1, 2008) and Section 3865, Hedges. In accordance with the transitional provisions in these new standards, these policies were adopted retrospectively without restatement. Prior period unrealized gains and losses related to the Company's foreign currency translation adjustments and net investment hedges are now included in accumulated other comprehensive income (AOCI). The cumulative impact of adopting these changes in 2007 was an increase to AOCI of $48 million.

FUTURE ACCOUNTING POLICIES

Business Combinations

The CICA issued Handbook Section 1582, *Business Combinations*, which replaces Section 1581. This new standard aligns accounting for business combinations under Canadian GAAP with IFRS. The standard requires assets and liabilities acquired in a business combination to be measured at fair value at the acquisition date. The standard also requires acquisition-related costs, such as advisory or legal fees, incurred to effect a business combination to be expensed in the period in which they are incurred. The adoption of this standard will impact the accounting treatment of future business combinations. The revised standard is effective for business combinations occurring on or after January 1, 2011; however, earlier application is permitted.

Consolidated Financial Statements and Non-Controlling Interests

The CICA issued Handbook Sections 1601, *Consolidated Financial Statements* and 1602, *Non-controlling Interests*, which together replace the former consolidated financial statements standard. Under the revised standards, non-controlling interests will be classified as a component of equity, and earnings and comprehensive income will be attributed to both the parent and non-controlling interest. The adoption of these standards is not expected to have a material impact to the Company's consolidated financial statements. The revised standards are effective January 1, 2011. Should the Company early adopt Section 1582, it would also be required to adopt Sections 1601 and 1602 at the same time.

International Financial Reporting Standards

The Canadian Accounting Standards Board (AcSB) confirmed in February 2008 that publicly accountable entities will be required to adopt IFRS for interim and annual financial statements beginning on January 1, 2011, including comparative financial statements for 2010.

Enbridge's preparations for IFRS conversion include preparing IFRS compliant accounting policies, drafting model IFRS financial disclosures, identifying accounting differences, developing and implementing systems solutions and process changes that support the preparation of 2010 comparative data as well as a sustainable conversion to IFRS in 2011.

The Audit, Finance and Risk Committee of the Board of Directors receives regular reports on the advancement of the conversion to IFRS.

Accounting and Reporting

To date, detailed IFRS compliant accounting policies and model financial statement disclosures are complete. The Company's IFRS compliant accounting policies differ in some regards from the Company's current accounting policies. The most significant differences are expected to impact the following areas:

- property, plant and equipment
- decommissioning liabilities (asset retirement obligations)
- impairments
- consolidation

The Company is carefully monitoring the International Accounting Standards Board's (IASB) project on Rate Regulated Activities. The IASB's exposure draft on Rate Regulated Activities, published in July 2009, would allow the Company to continue to apply rate regulated accounting with some changes. It is not possible to determine with certainty the extent of the changes to the Company's accounting for rate regulated activities until the final standard is available.

The IASB's project on joint ventures proposes to eliminate the proportionate consolidation of joint ventures. If the project proceeds as proposed, the Company would apply equity accounting to its joint venture interests under IFRS instead of proportionate consolidation. A final standard is expected to be published during the first quarter of 2010 after which the Company will be able to determine the impact of conversion to IFRS on its accounting for joint ventures.

The Company has selected IFRS 1 elective exemptions which are practical and provide the most relevant presentation on conversion to IFRS. The primary result of the exemptions selected is to apply certain IFRS differences prospectively, minimizing adjustments to the IFRS opening balance sheet. The Company also expects to elect to reduce cumulative translation differences to zero on the date of adoption. This change would impact the Company's retained earnings and AOCI balances, both within the equity section of the balance sheet. In addition, the IASB's exposure draft on Rate Regulated Activities includes an IFRS 1 exemption which would allow the Company to use the carrying amount of rate regulated property, plant and equipment, as calculated under Canadian GAAP, as the deemed cost for IFRS on the date of adoption. This would reduce changes to property, plant and equipment on adoption and, if it's available, the Company expects to use this exemption.

Information Systems and Business Processes

In January 2010, the Company implemented changes to information systems and processes which ensure that data needed for IFRS reporting of 2010 financial information for comparative purposes is gathered. The Company has also developed processes to derive the 2010 opening balance sheet under IFRS and is building processes and systems solutions to create 2010 IFRS compliant quarterly financial information for comparative purposes.

During the first quarter of 2010, the Company will determine the systems solution which will be implemented in 2011 to support and sustain IFRS changes after conversion. Process changes needed to sustain IFRS conversion starting in 2011 have been identified, and during 2010, process design and training is expected to be completed. Related impacts to internal controls over financial reporting and disclosure controls and procedures are expected to be identified during 2010.

Training and Communication

The Company has a comprehensive plan to train internal personnel who will be impacted by the conversion to IFRS. Training started during 2009 and is expected to continue throughout 2010. The Company has also commenced preparation of an external communication plan which will depend on the nature and magnitude of changes to the financial statements expected under IFRS.

Business Activities

The Company has reviewed the effect of IFRS conversion on its debt covenants, compensation agreements and hedging activities and does not expect the conversion to IFRS to significantly impact these activities or requirements.

The expected timing of key activities identified above may change prior to the IFRS conversion date due to changes in regulation, economic conditions or other factors and the issuance of new accounting standards or amendments to existing accounting standards, including and in addition to those noted above.

Controls and Procedures

DISCLOSURE CONTROLS AND PROCEDURES

Disclosure controls and procedures are designed to provide reasonable assurance that information required to be disclosed in reports filed with, or submitted to, securities regulatory authorities is recorded, processed, summarized and reported within the time periods specified under Canadian and United States securities law. As of the year ended December 31, 2009, an evaluation was carried out under the supervision of and with the participation of Enbridge's management, including the Chief Executive Officer and Chief Financial Officer, of the effectiveness of the design and operations of Enbridge's disclosure controls and procedures (as defined in Rule 13a-15(e) under the Securities Exchange Act of 1934). Based on that evaluation, the Chief Executive Officer and Chief Financial Officer concluded that the design and operation of these disclosure controls and procedures were effective in ensuring that information required to be disclosed by Enbridge in reports that it files with or submits to the Securities and Exchange Commission is recorded, processed, summarized and reported within the time periods required.

Management's Report on Internal Controls over Financial Reporting

Management of Enbridge is responsible for establishing and maintaining adequate internal control over financial reporting as such term is defined in the rules of the United States Securities and Exchange Commission and the Canadian Securities Administrators. The Company's internal control over financial reporting is a process designed under the supervision and with the participation of executive and financial officers to provide reasonable assurance regarding the reliability of financial reporting and the preparation of the Company's financial statements for external reporting purposes in accordance with GAAP.

The Company's internal control over financial reporting includes policies and procedures that:

- pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect transactions and dispositions of assets of the Company;
- provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles; and
- provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of the Company's assets that could have a material effect on the financial statements.

The Company's internal control over financial reporting may not prevent or detect all misstatements because of inherent limitations. Additionally, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions or deterioration in the degree of compliance with the Company's policies and procedures.

Management assessed the effectiveness of the Company's internal control over financial reporting as of December 31, 2009, based on the framework established in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on this assessment, Management concluded that the Company maintained effective internal control over financial reporting as of December 31, 2009.

During the year ended December 31, 2009, there has been no change in the Company's internal control over financial reporting that has materially affected, or is reasonably likely to materially affect, the Company's internal control over financial reporting.

Non-GAAP Reconciliations

(millions of Canadian dollars)	**2009**	2008	2007
GAAP earnings as reported	**1,555**	1,321	700
Significant after-tax non-recurring or non-operating factors and variances:			
Liquids Pipelines			
Enbridge System – impact of tax changes	**–**	–	(1)
Enbridge Regional Oil Sands System – leak remediation costs	**9**	–	–
Feeder Pipelines and Other – asset impairment loss	**–**	4	–
Natural Gas Delivery and Services			
EGD – colder weather than normal	**(17)**	(23)	(14)
EGD – interest accrual on GST refund	**(7)**	–	–
EGD – provision for one-time charges	**–**	3	–
EGD – impact of tax changes	**(21)**	–	(20)
Noverco – impact of tax changes	**(6)**	–	(7)
Offshore – property insurance recovery from hurricanes, net of costs incurred	**(4)**	–	(5)
Alliance Pipeline US – shipper claim settlement	**–**	(2)	–
Aux Sable – unrealized derivative fair value (gains)/losses	**36**	(56)	28
Aux Sable – loan forgiveness gain	**(7)**	–	–
Energy Services – unrealized derivative fair value (gains)/losses	**(3)**	(23)	3
Energy Services – SemGroup and Lehman credit loss/(recovery)	**(1)**	6	–
International – gain on sale of investments in OCENSA and CLH	**(329)**	(556)	(5)
Other – asset impairment loss	**10**	–	–
Other – adoption of new accounting standard	**3**	–	–
Other – gain on sale of investment in Inuvik Gas	**–**	(5)	–
Sponsored Investments			
EEP – unrealized derivative fair value (gains)/losses	**2**	(6)	6
EEP – asset impairment loss	**12**	–	–
EEP – Lakehead System billing correction	**(4)**	–	–
EEP – dilution gain on Class A unit issuance	**–**	(5)	(12)
EEP – gain on sale of KPC	**–**	–	(3)
EEP – impact of 2008 hurricanes and project write-offs	**–**	2	–
EIF – Alliance Canada shipper claim settlement	**–**	(1)	–
EIF – impact of tax changes	**–**	–	(2)
Corporate			
Unrealized derivative fair value gains	**(207)**	(26)	–
Unrealized foreign exchange gains on translation of intercompany balances, net	**(133)**	–	–
Gain on sale of investment in NTP	**(25)**	–	–
Impact of tax rate changes	**(8)**	–	(31)
Gain on sale of corporate aircraft	**–**	(5)	–
U.S. pipeline tax decision	**–**	32	–
Asset impairment loss	**–**	17	–
Adjusted Earnings	**855**	677	637

MANAGEMENT'S REPORT

To the Shareholders of Enbridge Inc.

FINANCIAL REPORTING

Management is responsible for the accompanying consolidated financial statements and all other information in this Annual Report. The consolidated financial statements have been prepared in accordance with Canadian generally accepted accounting principles and necessarily include amounts that reflect management's judgment and best estimates. Financial information contained elsewhere in this Annual Report is consistent with the consolidated financial statements.

The Board of Directors and its committees are responsible for all aspects related to governance of the Company. The Audit, Finance & Risk Committee of the Board, composed of directors who are unrelated and independent, has a specific responsibility to oversee management's efforts to fulfil its responsibilities for financial reporting and internal controls related thereto. The Committee meets with management, internal auditors and independent auditors to review the consolidated financial statements and the internal controls as they relate to financial reporting. The Audit, Finance & Risk Committee reports its findings to the Board for its consideration in approving the consolidated financial statements for issuance to the shareholders.

INTERNAL CONTROL OVER FINANCIAL REPORTING

Management is also responsible for establishing and maintaining adequate internal control over financial reporting. The Company's internal control over financial reporting includes policies and procedures to facilitate the preparation of relevant, reliable and timely information, to prepare consolidated financial statements for external reporting purposes in accordance with generally accepted accounting principles and provide reasonable assurance that assets are safeguarded.

Management assessed the effectiveness of the Company's internal control over financial reporting as of December 31, 2009, based on the framework established in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on this assessment, management concluded that the Company maintained effective internal control over financial reporting as of December 31, 2009.

PricewaterhouseCoopers LLP, independent auditors appointed by the shareholders of the Company, conducts an examination of the consolidated financial statements in accordance with Canadian generally accepted auditing standards.

Patrick D. Daniel	**J. Richard Bird**
President & Chief Executive Officer	Executive Vice President & Chief Financial Officer

February 18, 2010

INDEPENDENT AUDITORS' REPORT

To the Shareholders of Enbridge Inc.

We have completed integrated audits of Enbridge Inc.'s 2009, 2008 and 2007 consolidated financial statements and of its internal control over financial reporting as at December 31, 2009. Our opinions, based on our audits, are presented below.

CONSOLIDATED FINANCIAL STATEMENTS

We have audited the accompanying consolidated statements of financial position of Enbridge Inc. as at December 31, 2009 and December 31, 2008, and the related consolidated statements of earnings, comprehensive income, shareholders' equity and cash flows for each of the years in the three year period ended December 31, 2009. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits of the Company's financial statements as at December 31, 2009 and December 31, 2008, and for each of the years in the three year period ended December 31, 2009 in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform an audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit of financial statements includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. A financial statement audit also includes assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Company as at December 31, 2009 and December 31, 2008, and the results of its operations and its cash flows for each of the years in the three year period ended December 31, 2009 in accordance with Canadian generally accepted accounting principles.

INTERNAL CONTROL OVER FINANCIAL REPORTING

We have also audited Enbridge Inc.'s internal control over financial reporting as at December 31, 2009, based on criteria established in Internal Control - Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the effectiveness of the Company's internal control over financial reporting based on our audit.

We conducted our audit of internal control over financial reporting in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. An audit of internal control over financial reporting includes obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we consider necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

"PricewaterhouseCoopers" refers to PricewaterhouseCoopers LLP, an Ontario limited liability partnership, or, as the context requires, the PricewaterhouseCoopers global network or other member firms of the network, each of which is a separate legal entity.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as at December 31, 2009 based on criteria established in Internal Control—Integrated Framework issued by the COSO.

PricewaterhouseCoopers LLP

Chartered Accountants
Calgary, Alberta, Canada

February 18, 2010

COMMENTS BY AUDITORS FOR U.S. READERS ON CANADA-U.S. REPORTING DIFFERENCES

In the United States, reporting standards for auditors require the addition of an explanatory paragraph (following the opinion paragraph) when there is a change in accounting principles that has a material effect on the comparability of the Company's financial statements, such as the changes described in notes 3 to the consolidated financial statements. Our report to the shareholders dated February 18, 2010 is expressed in accordance with Canadian reporting standards, which do not require a reference to such a change in accounting principles in the Independent Auditors' Report when the change is properly accounted for and adequately disclosed in the financial statements.

PricewaterhouseCoopers LLP

Chartered Accountants
Calgary, Alberta, Canada

February 18, 2010

CONSOLIDATED STATEMENTS OF EARNINGS

Year ended December 31,	2009	2008	2007
(millions of Canadian dollars, except per share amounts)			
Revenues			
Commodity sales	**9,720**	13,432	9,536
Transportation and other services	**2,746**	2,699	2,383
	12,466	16,131	11,919
Expenses			
Commodity costs	**9,011**	12,792	9,009
Operating and administrative	**1,430**	1,312	1,164
Depreciation and amortization	**764**	658	597
	11,205	14,762	10,770
	1,261	1,369	1,149
Income from Equity Investments	**198**	177	168
Other Investment Income *(Note 28)*	**678**	198	195
Interest Expense *(Note 16)*	**(597)**	(551)	(550)
Gain on Sale of Investments *(Note 6)*	**365**	700	–
	1,905	1,893	962
Non-Controlling Interests	**(37)**	(56)	(46)
	1,868	1,837	916
Income Taxes *(Note 26)*	**(306)**	(509)	(209)
Earnings	**1,562**	1,328	707
Preferred Share Dividends	**(7)**	(7)	(7)
Earnings Applicable to Common Shareholders	**1,555**	1,321	700
Earnings per Common Share *(Note 20)*	**4.27**	3.67	1.97
Diluted Earnings per Common Share *(Note 20)*	**4.25**	3.64	1.95

The accompanying notes are an integral part of these consolidated financial statements.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

Year ended December 31,	2009	2008	2007
(millions of Canadian dollars)			
Earnings	**1,562**	1,328	707
Other Comprehensive Income/(Loss)			
Change in unrealized gain/(loss) on cash flow hedges, net of tax	**(54)**	(127)	97
Change in unrealized gain/(loss) on net investment hedges, net of tax	**151**	(160)	175
Reclassification to earnings of realized gain/(loss) on cash flow hedges, net of tax	**114**	(1)	(7)
Reclassification to earnings of unrealized cash flow hedges, net of tax *(Note 6)*	**(20)**	–	–
Other comprehensive income/(loss) from equity investees, net of tax	**(24)**	49	(20)
Non-controlling interests in other comprehensive income	**72**	(101)	92
Change in foreign currency translation adjustment	**(815)**	658	(534)
Other Comprehensive Income/(Loss)	**(576)**	318	(197)
Comprehensive Income	**986**	1,646	510

The accompanying notes are an integral part of these consolidated financial statements.

CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY

Year ended December 31,	2009	2008	2007
(millions of Canadian dollars, except per share amounts)			
Preferred Shares *(Note 20)*	**125**	125	125
Common Shares *(Note 20)*			
Balance at beginning of year	**3,194**	3,027	2,416
Common shares issued	**4**	–	567
Dividend reinvestment and share purchase plan	**143**	131	18
Shares issued on exercise of stock options	**38**	36	26
Balance at End of Year	**3,379**	3,194	3,027
Contributed Surplus			
Balance at beginning of year	**38**	26	18
Stock-based compensation	**19**	14	9
Options exercised	**(3)**	(2)	(1)
Balance at End of Year	**54**	38	26
Retained Earnings			
Balance at beginning of year	**3,383**	2,537	2,323
Earnings applicable to common shareholders	**1,555**	1,321	700
Common share dividends declared	**(555)**	(489)	(453)
Dividends paid to reciprocal shareholder	**17**	14	14
Cumulative impact of change in accounting policy *(Note 3)*	**–**	–	(47)
Balance at End of Year	**4,400**	3,383	2,537
Accumulated Other Comprehensive Income/(Loss) *(Note 22)*			
Balance at beginning of year	**33**	(285)	(136)
Other comprehensive income/(loss)	**(576)**	318	(197)
Cumulative impact of change in accounting policy *(Note 3)*	**–**	–	48
Balance at End of Year	**(543)**	33	(285)
Reciprocal Shareholding *(Note 11)*			
Balance at beginning of year	**(154)**	(154)	(136)
Participation in common shares issued	**–**	–	(18)
Balance at End of Year	**(154)**	(154)	(154)
Total Shareholders' Equity	**7,261**	6,619	5,276
Dividends Paid per Common Share	**1.48**	1.32	1.23

The accompanying notes are an integral part of these consolidated financial statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

Year ended December 31, *(millions of Canadian dollars)*	2009	2008	2007
Operating Activities			
Earnings	**1,562**	1,328	707
Depreciation and amortization	**764**	658	597
Unrealized (gain)/loss on derivative instruments	**(204)**	(120)	32
Allowance for equity funds used during construction	**(135)**	(59)	(15)
Equity earnings in excess of cash distributions	**(9)**	(82)	(35)
Gain on reduction of ownership interest	**–**	(12)	(34)
Gain on sale of investments *(Note 6)*	**(365)**	(700)	–
Future income taxes	**218**	258	41
Goodwill and asset impairment losses	**11**	23	–
Non-controlling interests	**37**	56	46
Other	**(105)**	48	19
Changes in operating assets and liabilities *(Note 29)*	**243**	(26)	4
	2,017	1,372	1,362
Investing Activities			
Long-term investments	**(359)**	(659)	(20)
Affiliate loans, net	**(145)**	–	15
Proceeds on sale of investments *(Note 6)*	**535**	1,383	–
Sale of property, plant and equipment	**87**	–	–
Settlement of hedges	**6**	(47)	–
Additions to property, plant and equipment *(Note 4)*	**(3,225)**	(3,545)	(2,231)
Additions to intangible assets	**(95)**	(91)	(68)
Change in construction payable	**(110)**	106	75
	(3,306)	(2,853)	(2,229)
Financing Activities			
Net change in short-term borrowings	**(366)**	329	(262)
Net change in commercial paper and credit facility draws	**632**	751	337
Debenture and term note issues	**1,500**	498	1,342
Debenture and term note repayments	**(516)**	(602)	(635)
Net change in Southern Lights project financing	**343**	1,238	–
Non-recourse debt issues	**106**	38	57
Non-recourse debt repayments	**(172)**	(65)	(59)
Distributions to non-controlling interests	**(33)**	(10)	(18)
Common shares issued	**36**	29	584
Preferred share dividends	**(7)**	(7)	(7)
Common share dividends	**(414)**	(359)	(435)
	1,109	1,840	904
Effect of translation of foreign denominated cash and cash equivalents	**(35)**	16	(10)
Increase/(Decrease) in Cash and Cash Equivalents	**(215)**	375	27
Cash and Cash Equivalents at Beginning of Year	**542**	167	140
Cash and Cash Equivalents at End of Year [1]	**327**	542	167
Supplementary Cash Flow Information			
Income taxes paid *(Note 26)*	**205**	161	226
Interest paid *(Note 16)*	**656**	607	607

The accompanying notes are an integral part of these consolidated financial statements.

1 *Cash and cash equivalents consists of $184 million (2008–$68 million; 2007–$79 million) of cash and $143 million (2008–$474 million; 2007–$88 million) of short-term investments and includes restricted cash of $59 million (2008–$81 million; 2007–$64 million).*

CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

December 31,	2009	2008
(millions of Canadian dollars)		
Assets		
Current Assets		
Cash and cash equivalents	**327**	542
Accounts receivable and other *(Note 7)*	**2,484**	2,322
Inventory *(Note 8)*	**784**	845
	3,595	3,709
Property, Plant and Equipment, net *(Note 9)*	**18,850**	16,157
Long-Term Investments *(Note 11)*	**2,312**	2,492
Deferred Amounts and Other Assets *(Note 12)*	**2,425**	1,318
Intangible Assets *(Note 13)*	**488**	458
Goodwill *(Note 14)*	**372**	389
Future Income Taxes *(Note 26)*	**127**	178
	28,169	24,701
Liabilities and Shareholders' Equity		
Current Liabilities		
Short-term borrowings *(Note 16)*	**508**	874
Accounts payable and other *(Note 15)*	**2,463**	2,411
Interest payable	**104**	102
Current maturities of long-term debt *(Note 16)*	**601**	534
Current maturities of non-recourse long-term debt *(Note 17)*	**113**	185
	3,789	4,106
Long-Term Debt *(Note 16)*	**11,581**	10,155
Non-Recourse Long-Term Debt *(Note 17)*	**1,393**	1,474
Other Long-Term Liabilities *(Note 18)*	**1,207**	259
Future Income Taxes *(Note 26)*	**2,211**	1,291
	20,181	17,285
Non-Controlling Interests *(Note 19)*	**727**	797
Shareholders' Equity		
Share capital		
Preferred shares *(Note 20)*	**125**	125
Common shares *(Note 20)*	**3,379**	3,194
Contributed surplus	**54**	38
Retained earnings	**4,400**	3,383
Accumulated other comprehensive income/(loss) *(Note 22)*	**(543)**	33
Reciprocal shareholding *(Note 11)*	**(154)**	(154)
	7,261	6,619
Commitments and Contingencies *(Note 31)*		
	28,169	24,701

The accompanying notes are an integral part of these consolidated financial statements.

Approved by the Board of Directors:

David A. Arledge
Chair

David A. Leslie
Director

1. General Business Description

Enbridge Inc. (Enbridge or the Company) is a publicly traded energy transportation and distribution company. Enbridge conducts its business through four operating segments identified based on products and services offered: Liquids Pipelines, Natural Gas Delivery and Services, Sponsored Investments, and Corporate. These operating segments are strategic business units established by senior management to facilitate the achievement of the Company's long-term objectives, to aid in resource allocation decisions and to assess operational performance.

LIQUIDS PIPELINES

Liquids Pipelines includes the operation and construction of the Enbridge crude oil mainline system and feeder pipelines that transport crude oil and other liquid hydrocarbons. Liquids Pipelines consists of crude oil, natural gas liquids (NGLs) and refined products pipelines and terminals in Canada and the United States.

NATURAL GAS DELIVERY AND SERVICES

Natural Gas Delivery and Services consists of natural gas utility operations, investments in natural gas pipelines, the Company's commodity marketing businesses and international activities.

The core of the Company's natural gas utility operations is Enbridge Gas Distribution Inc. (EGD) which serves residential, commercial, industrial and transportation customers, primarily in central and eastern Ontario as well as northern New York State. This business segment also includes natural gas distribution activities in Quebec and New Brunswick.

Investments in natural gas pipelines include the Company's interests in the United States portion of Alliance Pipeline (Alliance Pipeline US), Vector Pipeline and transmission and gathering pipelines in the Gulf of Mexico.

This segment also includes the Company's investment in Aux Sable, a natural gas fractionation and extraction business.

The commodity marketing businesses manage the Company's volume commitments on Alliance and Vector Pipelines as well as perform commodity storage, transport and supply management services, as principal and agent.

SPONSORED INVESTMENTS

Sponsored Investments includes the Company's 27.0% ownership interest in Enbridge Energy Partners, L.P. (EEP), Enbridge's funding of 66.7% of the United States segment of the Alberta Clipper Project through EEP and Enbridge Energy, L.P. (EELP) and a 72% economic interest (41.9% voting interest) in Enbridge Income Fund (EIF). Enbridge manages the day-to-day operations of, and develops and assesses opportunities for each of these investments, including both organic growth and acquisition opportunities.

EEP transports crude oil and other liquid hydrocarbons through common carrier and feeder pipelines and transports, gathers, processes and markets natural gas and NGLs. EIF is a publicly traded income fund whose primary operations include a crude oil and liquids pipeline and gathering system, a 50% interest in the Canadian portion of Alliance Pipeline and partial interests in several green energy investments.

CORPORATE

Corporate consists of new business development activities and investing and financing activities, including general corporate investments and financing costs not allocated to the business segments. Corporate also includes the Company's investments in green energy projects.

2. Summary of Significant Accounting Policies

The consolidated financial statements of the Company are prepared in accordance with Canadian generally accepted accounting principles (Canadian GAAP). These accounting principles are different in some respects from United States generally accepted accounting principles (U.S. GAAP) and the significant differences that impact the Company's consolidated financial statements are described in Note 33. Amounts are stated in Canadian dollars unless otherwise noted.

The preparation of financial statements in conformity with Canadian GAAP requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses as well as the disclosure of contingent assets and liabilities in the consolidated financial statements. Significant estimates and assumptions used in preparation of the consolidated financial statements include, but are not limited to: carrying value of regulatory assets and liabilities *(Note 5)*; depreciation rates and carrying value of property, plant and equipment *(Note 9)*; amortization rates of intangible assets *(Note 13)*; measurement of goodwill *(Note 14)*; valuation of share based compensation *(Note 21)*; fair values of financial instruments *(Notes 23 and 24)*; income taxes *(Note 26)*; post-employment benefits *(Note 27)*; and commitments and contingencies *(Note 31)*. Actual results could differ from these estimates.

Subsequent events have been evaluated through to February 18, 2010, the date on which the consolidated financial statements were approved by the Board of Directors and were available to be issued.

BASIS OF PRESENTATION

The consolidated financial statements include the accounts of Enbridge Inc., its subsidiaries and its proportionate share of the accounts of joint ventures. EIF is consolidated in the accounts of the Company because it is a variable interest entity. The Company is the primary beneficiary of EIF through a combination of a 41.9% equity interest and a preferred unit investment. Investments in entities which are not subsidiaries or joint ventures, but over which the Company exercises significant influence, are accounted for using the equity method. Other investments are accounted for according to their classification as held to maturity, loans and receivables or available for sale (see Financial Instruments).

REGULATION

Certain of the Company's Liquids Pipelines and Natural Gas Delivery and Services businesses are subject to regulation by various authorities including, but not limited to, the National Energy Board (NEB), the Federal Energy Regulatory Commission (FERC), the Energy Resources Conservation Board in Alberta (ERCB), the New Brunswick Energy and Utilities Board (EUB) and the Ontario Energy Board (OEB). Regulatory bodies exercise statutory authority over matters such as construction, rates and ratemaking and agreements with customers. To recognize the economic effects of the actions of the regulator, the timing of recognition of certain revenues and expenses in these operations may differ from that otherwise expected under GAAP for non rate-regulated entities.

Regulatory assets represent amounts that are expected to be recovered from customers in future periods through rates. Regulatory liabilities represent amounts that are expected to be refunded to customers in future periods through rates. In the absence of rate regulation, the Company would generally not recognize regulatory assets or liabilities and the earnings impact would be recorded in the period the expenses are incurred or revenues are earned. Long-term regulatory assets are recorded in Deferred Amounts and Other Assets and current regulatory assets are recorded in Accounts Receivable and Other. Long-term regulatory liabilities are included in Other Long-Term Liabilities and current regulatory liabilities are recorded in Accounts Payable and Other. Regulatory assets are assessed for impairment if the Company identifies an event indicative of possible impairment.

Allowance for funds used during construction (AFUDC) is included in the cost of property, plant and equipment and is depreciated over future periods as part of the total cost of the related asset. AFUDC includes both an interest component and, if approved by the regulator, a cost of equity component. In the absence of rate regulation, the Company would capitalize only the interest component; therefore, the capitalized equity component, the corresponding earnings during the construction phase and the subsequent depreciation would not be recognized.

Certain regulators prescribe the pool method of accounting for property, plant and equipment where similar assets with comparable useful lives are grouped and depreciated as a pool. When those assets are retired or otherwise disposed of, gains and losses are not reflected in earnings but are booked as an adjustment to accumulated depreciation. Entities not subject to rate regulation write off the net book value of the retired asset and include any resulting gain or loss in earnings.

With the approval of the regulator, EGD capitalizes a percentage of certain operating costs. EGD is authorized to charge depreciation and earn a return on the net book value of such capitalized costs in future years. In the absence of rate regulation, a portion of such costs may be charged to current earnings.

Prior to January 1, 2009, contributions made to the defined benefit pension plan and the cost of providing post-employment benefits other than pensions (OPEB) for the regulated operations of EGD were expensed as paid, consistent with the recovery of such costs in rates. Canadian GAAP requires costs and obligations for defined benefit pension plans and OPEB to be determined using the projected benefit method and charged to earnings as services are rendered. Effective January 1, 2009, the Company began recording a net pension asset and a net OPEB liability with an offsetting regulatory liability and asset related to the contributions to the defined benefit plan and the cost of OPEB for the regulated operations in Natural Gas Delivery and Services *(Note 3)*. There was no impact to earnings or cash flows as a result of this change.

REVENUE RECOGNITION

For businesses which are not rate-regulated, revenues are recorded when products have been delivered or services have been performed and the amount of revenue can be reliably measured. Customer credit worthiness is assessed prior to agreement signing as well as throughout the contract duration.

For the rate-regulated portion of the Company's main Canadian crude oil pipeline system, revenue is recognized in a manner that is consistent with the underlying agreements as approved by the regulator. Certain Liquids Pipelines revenues are recognized under the terms of a committed 30-year delivery contract rather than the cash tolls received.

For rate-regulated operations in Sponsored Investments and in natural gas pipelines included in Natural Gas Delivery and Services, transportation revenues include amounts related to expenses recognized that are expected to be recovered from shippers in future tolls. Revenue is recognized in a given period for tolls received to the extent that expenses are incurred. Differences between the recorded transportation revenue and actual toll receipts give rise to a regulatory asset or liability.

For natural gas utility rate-regulated operations in Natural Gas Delivery and Services, revenue is recognized in a manner consistent with the underlying rate-setting mechanism as mandated by the regulator. Natural gas utilities revenues are recorded on the basis of regular meter readings and estimates of customer usage from the last meter reading to the end of the reporting period.

FINANCIAL INSTRUMENTS

The Company classifies financial assets and financial liabilities as held for trading, available for sale, loans and receivables, held to maturity, other financial liabilities or derivatives in qualifying hedging relationships. All financial instruments are initially recorded at fair value on the consolidated statement of financial position. Subsequent measurement of the financial instrument is based on its classification.

Held for Trading

Financial assets and liabilities that are classified as held for trading are measured at fair value with changes in fair value recognized in earnings in Commodity Costs, Other Investment Income and Interest Expense. The Company has classified Cash and Cash Equivalents and its non-qualifying derivative instruments as held for trading.

Available for Sale

Financial assets that are available for sale are measured at fair value, with changes in those fair values recorded in Other Comprehensive Income (OCI) unless actively quoted prices are not available for fair value measurement, in which case available for sale assets are measured at cost. Generally, the Company classifies equity investments in other entities that do not trade on an actively quoted market as available for sale. Dividends received from available for sale financial assets are recognized in earnings when the right to receive payment is established.

Loans and Receivables

Loans and receivables, which include Accounts Receivable and Other and long-term notes receivable, are measured at amortized cost using the effective interest rate method, net of any impairment losses recognized.

Held to Maturity

The Company has classified certain investments which are non-derivative financial assets as held to maturity. Held to maturity investments are measured at amortized cost using the effective interest rate method.

Other Financial Liabilities

Other financial liabilities are recorded at amortized cost using the effective interest rate method and include Short-term Borrowings, Accounts Payable and Other, Interest Payable, Long-term Debt and Non-recourse Long-term Debt.

Derivatives in Qualifying Hedging Relationships

The Company uses derivative financial instruments to manage changes in commodity prices, foreign exchange rates, interest rates and certain compensation tied to its share price. Hedge accounting is optional and requires the Company to document the hedging relationship and test the hedging item's effectiveness in offsetting changes in fair values or cash flows of the underlying hedged item on an ongoing basis. The Company presents the earnings and cash flow effects of hedging items with the hedged transaction. Derivatives in qualifying hedging relationships are categorized as cash flow hedges, fair value hedges and net investment hedges.

Cash Flow Hedges

The Company uses cash flow hedges to manage changes in commodity prices, foreign exchange rates, interest rates and certain compensation tied to its share price. The effective portion of the change in the fair value of a cash flow hedging instrument is recorded in OCI and is reclassified to earnings when the hedged item impacts earnings or to the carrying value of the related non-financial asset. Any hedge ineffectiveness is recorded in current period earnings.

If a derivative instrument designated as a cash flow hedge ceases to be effective or is terminated, hedge accounting is discontinued and the gain or loss at that date is deferred in OCI and recognized concurrently with the related transaction. If a hedged anticipated transaction is no longer probable, the gain or loss is recognized immediately in earnings. Subsequent gains and losses from ineffective derivative instruments are recognized in earnings in the period in which they occur.

Fair Value Hedges

The Company may use fair value hedges to hedge the fair value of debt instruments or commodity positions. The change in the fair value of the hedging instrument is recorded in earnings with changes in the fair value of the hedged asset or liability that is designated as part of the hedging relationship. If a fair value hedge is discontinued or ceases to be effective, the hedged asset or liability, otherwise required to be carried at cost or amortized cost, ceases to be remeasured at fair value and the cumulative fair value adjustment to the carrying value of the hedged item is recognized in earnings over the remaining life of the hedged item.

Net Investment Hedges

The Company uses net investment hedges to manage the carrying values of United States dollar denominated foreign operations. The effective portion of the change in the fair value of the hedging instrument is recorded in OCI. Any ineffectiveness is recorded in current period earnings. Amounts recorded in Accumulated Other Comprehensive Income/Loss (AOCI) are recognized in earnings when there is a reduction of the hedged net investment resulting from a disposal of the foreign operation.

Impairment

With respect to available for sale instruments, the Company assesses at each balance sheet date whether there is objective evidence that a financial asset is impaired. If there is determined to be objective evidence of impairment, the Company internally values the expected discounted cash flows using observable market inputs and determines whether the decline below carrying value is other than temporary. If the decline is determined to be other than temporary, an impairment charge is recorded in earnings with an offsetting reduction to the carrying value of the asset.

With respect to loans and receivables, the Company assesses the assets for impairment when it no longer has a reasonable assurance of timely collection. If evidence of impairment is noted, the Company reduces the value of the loan or receivable to its estimated realizable amount, determined using discounted expected future cash flows.

Transaction Costs

Transaction costs are incremental costs directly related to the acquisition of a financial asset or the issuance of a financial liability. The Company incurs transaction costs primarily through the issuance of debt and classifies these costs with the related debt. These costs are amortized using the effective interest rate method over the life of the related debt instrument.

INCOME TAXES

The liability method of accounting for income taxes is followed. Future income tax assets and liabilities are recorded based on temporary differences between the tax bases of assets and liabilities and their carrying values for accounting purposes. Future income tax assets and liabilities are measured using the tax rate that is expected to apply when the temporary differences reverse *(Note 3)*.

FOREIGN CURRENCY TRANSLATION

The Company's foreign operations are primarily self-sustaining. The financial statements of self-sustaining foreign operations are translated into Canadian dollars using the current rate method. Under this method, assets and liabilities are translated using period-end exchange rates and revenues and expenses are translated using monthly average rates. Gains and losses arising on translation of these operations are included in the cumulative translation adjustment component of AOCI.

Transactions denominated in foreign currencies are translated into Canadian dollars using the exchange rate prevailing at the date of transaction. Monetary assets and liabilities denominated in foreign currencies are translated to Canadian dollars using the rate of exchange in effect at the balance sheet date whereas non-monetary assets and liabilities are translated at the rate of exchange in effect on the date of the transaction. Exchange gains and losses resulting from translation are included in the Statement of Earnings in the period that they arise.

CASH AND CASH EQUIVALENTS

Cash and cash equivalents include short-term investments with a term to maturity of three months or less when purchased. Cash and cash equivalents include amounts in trust and proportionately consolidated cash from joint ventures.

INVENTORY

Inventory is primarily comprised of natural gas in storage held in EGD. Natural gas in storage is recorded at the quarterly prices approved by the OEB in the determination of distribution rates. The actual price of gas purchased may differ from the OEB approved price. The difference between the approved price and the actual cost of the gas purchased is deferred for future refund or collection as approved by the OEB. Other inventory, consisting primarily of commodities held in storage, is recorded at fair value as measured at the spot price less costs to sell *(Note 3)*.

PROPERTY, PLANT AND EQUIPMENT

Expenditures for construction, expansion, major renewals and betterments are capitalized. Maintenance and repair costs are expensed as incurred. Expenditures for project development are capitalized if they are expected to have a future benefit. The Company capitalizes interest incurred during construction. For rate-regulated assets, if approved, an allowance for equity funds used during construction (AEDC) is capitalized at rates authorized by the regulatory authorities. Depreciation of property, plant and equipment is provided on a straight-line basis over the estimated service lives of the assets commencing when the asset is placed in service.

IMPAIRMENT OF LONG-LIVED ASSETS

The Company reviews the carrying values of its long-lived assets as events or changes in circumstances warrant. If it is determined that the carrying value of an asset exceeds the undiscounted cash flows expected from the asset, the asset is written down to fair value.

DEFERRED AMOUNTS AND OTHER ASSETS

Deferred amounts and other assets include costs which regulatory authorities have permitted, or are expected to permit, to be recovered through future rates, contractual receivables under the terms of long-term delivery contracts, derivative financial instruments as well as pension assets. Certain deferred amounts are amortized on a straight-line basis over various periods depending on the nature of the charges.

INTANGIBLE ASSETS

Intangible assets consist primarily of acquired long-term transportation contracts and software costs, which are amortized on a straight-line basis over their expected lives *(Note 3)*.

GOODWILL

Goodwill represents the excess of the purchase price over the fair value of net identifiable assets on acquisition of a business. Goodwill is not subject to amortization but is tested for impairment at least annually. For the purposes of impairment testing, reporting units are identified as business operations within an operating segment. Potential impairment is identified when the carrying value of a reporting unit, including allocated goodwill, exceeds its fair value.

Goodwill impairment is measured as the excess of the carrying amount of the reporting unit's allocated goodwill over the implied fair value of the goodwill based on the fair value of the assets and liabilities of the reporting unit.

ASSET RETIREMENT OBLIGATIONS

Asset retirement obligations (AROs) associated with the retirement of long-lived assets are measured at fair value and recognized as Other Long-term Liabilities in the period when they can be reasonably determined. The fair value approximates the cost a third party would charge to perform the tasks necessary to retire such assets and is recognized at the present value of expected future cash flows. AROs are added to the carrying value of the associated asset and depreciated over the asset's useful life. The corresponding liability is accreted over time through charges to earnings and is reduced by actual costs of decommissioning and reclamation. The Company's estimates of retirement costs could change as a result of changes in cost estimates and regulatory requirements.

For certain of the Company's assets it is not possible to make a reasonable estimate of AROs due to the indeterminate timing and scope of the asset retirements.

POST-EMPLOYMENT BENEFITS

The Company maintains pension plans which provide defined benefit and defined contribution pension benefits.

Defined benefit pension plan costs are determined using actuarial methods and are funded through contributions determined using the projected benefit method, which incorporates management's best estimate of future salary levels, other cost escalations, retirement ages of employees and other actuarial factors. Pension cost is charged to earnings as services are rendered and includes:

- Cost of pension plan benefits provided in exchange for employee services rendered during the year;
- Amortization of the initial net transitional asset, prior service costs and amendments on a straight-line basis over the expected average remaining service period of the active employee group covered by the plans;
- Interest cost of pension plan obligations;
- Expected return on pension fund assets; and
- Amortization of cumulative unrecognized net actuarial gains and losses, in excess of 10% of the greater of the accrued benefit obligation or the fair value of plan assets, over the expected average remaining service life of the active employee group covered by the plans.

Actuarial gains and losses arise from the difference between the actual and expected rate of return on plan assets for that period or from changes in actuarial assumptions used to determine the accrued benefit obligation, including discount rate or salary inflation experience.

Pension plan assets are measured at fair value. The expected return on pension plan assets is determined using market related values and assumptions on the specific asset mix within the pension plan. The market related values reflect estimated return on investments consistent with long-term historical averages for similar assets.

For defined contribution plans, contributions made by the Company are expensed in the period in which the contribution occurs.

The Company also provides post-employment benefits other than pensions, including group health care and life insurance benefits for eligible retirees, their spouses and qualified dependants. The cost of such benefits is accrued during the years in which employees render service.

STOCK BASED COMPENSATION

Stock options granted are recorded using the fair value method. Under this method, compensation expense is measured at fair value at the grant date and is recognized on a straight-line basis over the shorter of the vesting period or the period to early retirement eligibility, with a corresponding credit to contributed surplus. Balances in contributed surplus are transferred to share capital when the options are exercised.

Performance Stock Units (PSUs) vest at the completion of a three-year term and Restricted Stock Units (RSUs) vest at the completion of a 35-month term. Both PSUs and RSUs are settled in cash. During the vesting term, an expense is recorded based on the number of units outstanding and the current market price of the Company's shares with an offset to Other Long-Term Liabilities. The value of the PSUs is also dependent on the Company's performance relative to performance targets set out under the plan.

COMPARATIVE AMOUNTS

Certain comparative amounts have been reclassified to conform with the current year's financial statement presentation.

3. Changes in Accounting Policies

ACCOUNTING FOR THE EFFECTS OF RATE REGULATION

Effective January 1, 2009, the Company adopted revisions to the Canadian Institute of Chartered Accountants (CICA) Handbook Section 1100, Generally Accepted Accounting Principles and Section 3465, Income Taxes. In accordance with the transitional provisions in these revised standards, the revisions to Section 1100 were adopted prospectively and accordingly, prior periods were not restated, while the revisions to Section 3465 were applied retrospectively without restatement of prior periods. The adoption of the revised standards did not impact the Company's earnings or cash flows.

Generally Accepted Accounting Principles

The revised standard no longer provides an exemption for rate-regulated entities to measure assets and liabilities on a basis other than in accordance with primary sources of Canadian GAAP. As a result, for the pension plans and OPEB included in EGD, the Company recognized post-employment benefit assets and liabilities for the amount of benefits expected to be included in future rates and recovered from, or paid to, customers. In addition, the Company reclassified certain EGD reserves for future removal and site restoration.

Pension Plans and OPEB

On adoption of the revised standard at January 1, 2009, the Company recognized a net pension asset of $157 million and a net OPEB liability of $75 million, with an offsetting long-term net pension regulatory liability and long-term net OPEB regulatory asset, respectively. At December 31, 2009, the Company had a net pension asset of $140 million and a net OPEB liability of $80 million, with an offsetting long-term net pension regulatory liability and a long-term net OPEB regulatory asset, respectively.

Future Removal and Site Restoration Reserves

At January 1, 2009, on adoption of the revised standard, the Company reclassified amounts collected for future removal and site restoration of $657 million, which were previously netted against Property, Plant and Equipment, to a long-term regulatory liability. At December 31, 2009, this long-term regulatory liability was $710 million.

Income Taxes

The revised standard removes the exemption for rate-regulated entities to recognize future income taxes to the extent they were expected to be included in regulator-approved future rates and recovered from or refunded to future customers. As a result, on January 1, 2009, the Company recognized a future income tax liability of $816 million on regulatory assets, primarily property, plant and equipment, with an offsetting long-term regulatory asset. A regulatory asset has been recognized as the associated future income tax liability is expected to be recoverable in future rates. At December 31, 2009, the Company had a future income tax liability of $829 million related to regulatory assets with an offsetting long-term regulatory asset.

INTANGIBLE ASSETS

Effective January 1, 2009, the Company adopted CICA Handbook Section 3064, *Goodwill and Intangible Assets*, which establishes standards for the recognition, measurement, presentation and disclosure of goodwill and intangible assets. As a result of adopting this standard, the Company reclassified certain software costs from Property, Plant and Equipment to Intangible Assets. This standard has been applied retrospectively and affects presentation only.

As a result of adopting this standard, on January 1, 2009, the Company reclassified $233 million of net software costs from Property, Plant and Equipment to Intangible Assets. At December 31, 2009, the Company had $289 million of net software costs recorded in Intangible Assets.

COMMODITY INVENTORY

Effective January 1, 2009, the Company changed its accounting policy for inventory held by its energy marketing businesses and began measuring commodity inventory at fair value, as measured at the spot price less costs to sell, rather than lower of cost or net realizable value. This measurement basis is a more relevant measurement for commodity inventory used for marketing purposes and better matches the commodity inventory with the derivatives used to "lock in" the margin. This change in accounting policy has been accounted for retrospectively and did not result in restatements of the comparative Consolidated Statements of Earnings, Comprehensive Income, Shareholders' Equity or Cash Flows for the years ended December 31, 2008 and 2007 and the comparative Consolidated Statement of Financial Position as at December 31, 2008 as the amounts were considered immaterial.

INVENTORIES

The CICA issued Handbook Section 3031, *Inventories*, effective January 1, 2008 which aligns accounting for inventories under Canadian GAAP with International Financial Reporting Standards (IFRS) and replaces Section 3030. The adoption of the revised standard did not have a significant effect on the Company.

CAPITAL DISCLOSURES AND FINANCIAL INSTRUMENTS— DISCLOSURES AND PRESENTATION

Effective January 1, 2008, the Company adopted new standards for *Capital Disclosures* (CICA Handbook Section 1535) and *Financial Instruments – Disclosures and Presentation* (CICA Handbook Sections 3862 and 3863). While the new standards did not change the Company's accounting policies, they resulted in additional disclosures.

FINANCIAL INSTRUMENTS, COMPREHENSIVE INCOME AND HEDGING RELATIONSHIPS

Effective January 1, 2007, the Company adopted CICA Handbook Section 1530, *Comprehensive Income*, Section 3251, *Equity*, Section 3855, *Financial Instruments – Recognition and Measurement*, Section 3861, *Financial Instruments – Disclosure and Presentation* (subsequently replaced by Sections 3862 and 3863 adopted by the Company on January 1, 2008) and Section 3865, *Hedges*. In accordance with the transitional provisions in these new standards, these policies were adopted retrospectively without restatement. Prior period unrealized gains and losses related to the Company's foreign currency translation adjustments and net investment hedges are now included in AOCI. The cumulative impact of adopting these changes in 2007 was an increase to AOCI of $48 million.

FUTURE ACCOUNTING POLICY CHANGES

Business Combinations

The CICA issued Handbook Section 1582, *Business Combinations*, which replaces Section 1581. This new standard aligns accounting for business combinations under Canadian GAAP with IFRS. The standard requires assets and liabilities acquired in a business combination to be measured at fair value at the acquisition date. The standard also requires acquisition-related costs, such as advisory or legal fees, incurred to effect a business combination to be expensed in the period in which they are incurred. The adoption of this standard will impact the accounting treatment of future business combinations. The revised standard is effective for business combinations occurring on or after January 1, 2011; however, earlier application is permitted.

Consolidated Financial Statements and Non-Controlling Interests

The CICA issued Handbook Sections 1601, *Consolidated Financial Statements* and 1602, *Non-controlling Interests*, which together replace the former consolidated financial statements standard. Under the revised standards, non-controlling interests will be classified as a component of equity, and earnings and comprehensive income will be attributed to both the parent and non-controlling interest. The adoption of these standards is not expected to have a material impact to the Company's consolidated financial statements. The revised standards are effective January 1, 2011. Should the Company early adopt Section 1582, it would also be required to adopt Sections 1601 and 1602 at the same time.

4. Segmented Information

Year ended December 31, 2009	Liquids Pipelines	Natural Gas Delivery and Services	Sponsored Investments	Corporate	Consolidated
(millions of Canadian dollars)					
Revenues	**1,333**	**10,776**	**313**	**44**	**12,466**
Commodity costs	**–**	**(9,011)**	**–**	**–**	**(9,011)**
Operating and administrative	**(565)**	**(709)**	**(113)**	**(43)**	**(1,430)**
Depreciation and amortization	**(230)**	**(419)**	**(88)**	**(27)**	**(764)**
	538	**637**	**112**	**(26)**	**1,261**
Income from equity investments	**–**	**10**	**188**	**–**	**198**
Other investment income and gain on sale of investments	**161**	**370**	**13**	**499**	**1,043**
Interest and preferred share dividends	**(144)**	**(257)**	**(56)**	**(147)**	**(604)**
Non-controlling interests	**(2)**	**(7)**	**(28)**	**–**	**(37)**
Income taxes	**(108)**	**(118)**	**(88)**	**8**	**(306)**
Earnings applicable to common shareholders	**445**	**635**	**141**	**334**	**1,555**

Year ended December 31, 2008	Liquids Pipelines	Natural Gas Delivery and Services	Sponsored Investments	Corporate	Consolidated
(millions of Canadian dollars)					
Revenues	1,170	14,650	298	13	16,131
Commodity costs	–	(12,792)	–	–	(12,792)
Operating and administrative	(492)	(685)	(102)	(33)	(1,312)
Depreciation and amortization	(181)	(392)	(78)	(7)	(658)
	497	781	118	(27)	1,369
Income from equity investments	–	30	148	(1)	177
Other investment income and gain on sale of investments	61	759	25	53	898
Interest and preferred share dividends	(111)	(270)	(60)	(117)	(558)
Non-controlling interests	(1)	(7)	(47)	(1)	(56)
Income taxes	(118)	(335)	(73)	17	(509)
Earnings applicable to common shareholders	328	958	111	(76)	1,321

Year ended December 31, 2007	Liquids Pipelines	Natural Gas Delivery and Services	Sponsored Investments	Corporate	Consolidated
(millions of Canadian dollars)					
Revenues	1,091	10,549	270	9	11,919
Commodity costs	–	(9,009)	–	–	(9,009)
Operating and administrative	(427)	(632)	(79)	(26)	(1,164)
Depreciation and amortization	(156)	(360)	(75)	(6)	(597)
	508	548	116	(23)	1,149
Income from equity investments	(1)	73	97	(1)	168
Other investment income and gain on sale of investments	16	88	38	53	195
Interest and preferred share dividends	(101)	(271)	(62)	(123)	(557)
Non-controlling interests	(1)	(6)	(38)	(1)	(46)
Income taxes	(134)	(88)	(54)	67	(209)
Earnings applicable to common shareholders	287	344	97	(28)	700

The measurement basis for preparation of segmented information is consistent with the significant accounting policies described in Note 2.

TOTAL ASSETS

December 31,	2009	2008
(millions of Canadian dollars)		
Liquids Pipelines	**10,763**	7,467
Natural Gas Delivery and Services	**11,207**	10,724
Sponsored Investments	**3,860**	3,766
Corporate	**2,339**	2,744
	28,169	24,701

ADDITIONS TO PROPERTY, PLANT AND EQUIPMENT [1]

December 31,	2009	2008
(millions of Canadian dollars)		
Liquids Pipelines	**2,662**	2,898
Natural Gas Delivery and Services	**440**	544
Sponsored Investments	**41**	53
Corporate	**217**	109
	3,360	3,604

1 Includes AEDC.

GEOGRAPHIC INFORMATION

Revenues [1]

Year ended December 31,	2009	2008	2007
(millions of Canadian dollars)			
Canada	**9,503**	12,459	8,346
United States	**2,963**	3,672	3,573
	12,466	16,131	11,919

1 Revenues are based on the country of origin of the product or services sold.

Property, Plant and Equipment

December 31,	2009	2008
(millions of Canadian dollars)		
Canada	**15,101**	12,107
United States	**3,749**	4,050
	18,850	16,157

5. Financial Statement Effects of Rate Regulation

GENERAL INFORMATION ON RATE REGULATION AND ITS ECONOMIC EFFECTS

A number of businesses within the Company are subject to regulation where the rates approved by the regulator are designed to recover the costs of providing products and services to customers, referred to as the cost of service toll methodology. The Company's significant regulated businesses and related accounting impacts are described below.

Enbridge System

The primary business activities of the Enbridge System are subject to regulation by the NEB. Tolls are based on a cost of service methodology and are based on agreements with customers which are filed with the NEB for approval.

The incentive tolling settlement (ITS) was effective from January 1, 2005 to December 31, 2009 and defines the methodology for calculation of tolls and the revenue requirement on the core component of the Enbridge System in Canada. Toll adjustments, for variances from requirements defined in the ITS, are filed annually with the regulator for approval. Surcharges are also determined for a number of system expansion components and are added to the base toll determined for the core system. Discussions and negotiations continue with the Canadian Association of Petroleum Producers (CAPP) and a representative shipper group for an extension to the 2005 ITS which will support a competitive toll structure. The Company anticipates it will reach a settlement by the end of the first quarter of 2010. In the event that a settlement cannot be reached, the Company could file a cost of service application.

Athabasca Pipeline

Athabasca Pipeline is regulated by the ERCB. Tolls are established based on long-term transportation agreements with individual shippers.

Vector Pipeline

Vector Pipeline is an interstate natural gas pipeline in the United States with a FERC approved tariff that establishes rates, terms and conditions governing its service to customers. Rates are determined using a cost of service methodology. Tariff changes may only be implemented upon approval by the FERC. Tolls for the year ended December 31, 2009 include an after-tax return on equity (ROE) component of 11.07% (2008–11.04%; 2007–10.75%).

Alliance Pipeline

The United States portion of the Alliance Pipeline is regulated by the FERC and the Canadian portion of the pipeline is regulated by the NEB. Shippers on the Alliance Pipeline are subject to 15-year transportation contracts that expire in December 2015, with a cost of service toll methodology. Toll adjustments are filed annually with the regulator. The tolls for the year ended December 31, 2009 include an after-tax ROE component of 10.88% (2008–10.88%; 2007–10.88%) for the United States portion and 11.26% (2008–11.26%; 2007–11.26%) for the Canadian portion. Alliance Pipeline tolls are based on a deemed 70% debt and 30% equity structure.

Enbridge Gas Distribution

EGD's gas distribution operations are regulated by the OEB. EGD's rates are based on a revenue per customer cap incentive regulation (IR) methodology, expiring in December 2012, which adjusts revenues, and consequently rates, annually and relies on an annual process to forecast volume and customer additions.

EGD's after-tax rate of return on common equity embedded in rates was 8.39% for the year ended December 31, 2009 (2008–8.39%; 2007–8.39%) based on a 36% (2008–36%; 2007–36%) deemed common equity component of capital for regulatory purposes.

Enbridge Gas New Brunswick

Enbridge Gas New Brunswick (EGNB) is regulated by the EUB and follows a cost of service tolling methodology. An application for rate adjustments is filed annually for EUB approval. EGNB's after-tax ROE was 13.00% (2008–13.00%; 2007–13.00%) based on equity which is capped at 50%.

FINANCIAL STATEMENT EFFECTS

Accounting for rate-regulated entities has resulted in the recognition of the following regulatory assets and liabilities:

December 31,	2009	2008	Estimated Settlement Period (years)	Earnings Impact [1] 2009	2008	2007
(millions of Canadian dollars)						
Regulatory Assets/(Liabilities)						
Liquids Pipelines						
Future income taxes [2]	**504**	–	–	**49**	–	–
Enbridge System tolling deferrals [3]	**98**	114	1	**(16)**	(30)	(23)
Power purchase arrangements [4]	**(2)**	(21)	1–3	**(19)**	3	(24)
	600	93		**14**	(27)	(47)
Natural Gas Delivery and Services						
Future income taxes [2]	**227**	–	–	**(11)**	–	–
Deferred transportation revenue [5]	**185**	267	14–16	**(6)**	1	6
EGNB regulatory deferral [6]	**155**	133	31	**15**	10	10
Class action lawsuit settlement [7]	**20**	20	3	**–**	(1)	–
Shared savings mechanism [8]	**14**	8	1	**–**	–	–
Ontario hearing costs [9]	**6**	5	2	**–**	(2)	(1)
Transportation revenue adjustment [10]	**3**	7	1	**(2)**	1	(3)
Unaccounted for gas variance [11]	**10**	1	1	**6**	(4)	11
Future removal and site restoration reserves [12]	**(710)**	–	–	**6**	–	–
Purchased gas variance [13]	**(227)**	(75)	1	**–**	–	–
Pension plans and OPEB, net [14]	**(60)**	–	–	**(2)**	–	–
Earnings sharing deferral [15]	**(25)**	(6)	1	**–**	–	–
Transactional services deferral [16]	**(14)**	(7)	1	**–**	–	–
	(416)	353		**6**	5	23
Sponsored Investments						
Future income taxes [2]	**98**	–	–	**(11)**	–	–
Deferred transportation revenue [5]	**91**	80	16	**5**	6	8
	189	80		**(6)**	6	8
	373	526		**14**	(16)	(16)

1 *The effect of a number of the Company's businesses being subject to rate regulation increased/(decreased) after-tax reported earnings by the identified amounts.*

2 *This regulatory asset is an offsetting balance to a future income tax liability recognized on adoption of a revised accounting standard (Note 3). The future income tax liability primarily relates to future income taxes associated with property, plant and equipment. The balance has been recognized as a regulatory asset since the flow-through treatment of taxes for rate-setting purposes would ensure eventual recovery of these balances as the temporary differences reverse. The recovery period will depend on the period in which the future income tax amounts reverse. In the absence of rate regulation, the liability method of accounting for income taxes would be utilized and future income tax expense would be recorded.*

3 *Tolls on the Enbridge System are calculated in accordance with the ITS, System Expansion Program (SEP), Terrace, Southern Access, Line 4 and the Alberta Clipper agreements and are established each year based on capacity and the allowed revenue requirement. Where actual volumes shipped on the pipeline do not result in collection of the annual revenue requirement, a regulatory asset is recognized and incorporated into tolls in the subsequent year. Recovery in the subsequent year, in whole or in part, is dependent upon realizing shipping volumes consistent with tolling model forecasts. Under or over collections are rolled into subsequent years. In addition, other tolling deferrals are recorded in accordance with the various agreements.*

4 *The power purchase arrangements liability represents the fair value of fixed price contracts and related financial instruments used to manage the mix of fixed and floating power costs (Note 23). Under rate regulation any fair value changes are passed to shippers through tolls. In the absence of rate regulation, these changes would impact earnings in the year incurred.*

5 *Deferred transportation revenue is related to the cumulative difference between Canadian GAAP depreciation expense for Alliance and Vector Pipelines and depreciation expense included in the regulated transportation rates. The Company expects to recover this difference over a number of years when depreciation rates in the transportation agreements are expected to exceed Canadian GAAP depreciation rates: for Alliance Pipeline US beginning in 2009, for Alliance Pipeline Canada beginning in 2011 and ending in 2025 and for Vector Pipeline beginning in 2008 and ending in 2023. This regulatory asset is not included in the rate base.*

6 *A regulatory deferral account captures the cumulative difference between EGNB's distribution revenues and its cost of service revenue requirement during the development period. The regulatory deferral account balance is expected to be amortized over a recovery period approved by the EUB expected to commence at the end of the development period in 2010 and expected to end in 2040.*

7 *Class action lawsuit settlement deferral represents amounts paid towards the settlement of a class action lawsuit related to late payment penalties. Pursuant to an OEB decision in February 2008, these amounts will be recovered from customers over a five-year period commencing in 2008. In the absence of rate regulation these costs would be expensed as incurred.*

8 *Shared savings mechanism (SSM) deferral represents the benefit derived by EGD as a result of its energy efficiency programs. EGD has historically been granted OEB approval to recover the SSM amount through rates after a detailed review by the OEB. The process of review and subsequent recovery may extend over a few years. In the absence of rate regulation, the amount would be included in earnings in the year of approval.*

9 *Ontario hearing costs are incurred by EGD for the rate hearing process. EGD has historically been granted OEB approval for recovery of such hearing costs, generally within two years. In the absence of rate regulation these costs would be expensed as incurred.*

10 *The deferred transportation revenue adjustment is the cumulative difference between actual expenses of Alliance Pipeline US and estimated expenses included in transportation rates. The deferred transportation revenue adjustment is recoverable, typically in the following year, under the long-term transportation agreements and is not included in the rate base.*

11 *Unaccounted for gas variance represents the difference between the total gas distributed by EGD and the amount of gas billed or billable to ratepayers, to the extent it is different from the approved gas variance. EGD has deferred unaccounted for gas variance and has historically been granted approval for recovery or required refund of this amount in the subsequent year. In the absence of rate regulation this variance would be included in Commodity Costs.*

12 *Future removal and site restoration reserves results from the adoption of a revised accounting standard in 2009 (Note 3). With the approval of the regulators, certain of the Company's businesses collect amounts from customers to fund future costs for removal and site restoration relating to property, plant and equipment and are collected as part of depreciation charged on property, plant and equipment. The balance represents the net amount that EGD has collected from customers, net of actual costs expended on removal and site restoration as at December 31, 2009. In the absence of rate regulation, this balance would not be recorded as amounts would not have been collected from customers.*

13 *Purchased gas variance is the difference between the actual cost and the approved cost of gas reflected in rates. EGD has been granted approval to refund this balance to customers in the following year. In the absence of rate regulation the actual cost of gas would be included in commodity costs and commodity sales would be adjusted by the purchased gas variance.*

14 *This pension plan and OPEB account results from the adoption of a revised accounting standard in 2009 (Note 3). EGD continues to record and recover pension plan contributions and OPEB expenditures through rates on a cash basis. However, as a result of the revised accounting standard, a net asset was recorded representing the amount of pension and OPEB benefits calculated on an accrual basis, with an offsetting net regulatory liability. The settlement period is not determinable. In the absence of rate regulation, there would be no regulatory offset to the net asset.*

15 *Earnings sharing deferral represents amounts relating to the earnings sharing mechanism, which forms part of the IR Settlement. The earnings sharing is payable to ratepayers and represents 50% of earnings excluding the effects of weather, represented by the ROE in excess of 100 basis points above the notional allowed utility ROE. The December 31, 2009 balance relates to the years ended December 31, 2009 and 2008. There would be no change in the treatment of this item in the absence of rate regulation.*

16 *Transactional services deferral represents the ratepayer portion of excess earnings generated from optimization of storage and pipeline capacity. EGD has historically been required to refund the amount to ratepayers in the following year. There would be no change in the treatment of this item in the absence of rate regulation.*

OTHER ITEMS AFFECTED BY RATE REGULATION

Future Income Taxes

On January 1, 2009, the Company adopted a change in accounting standard that impacted the recognition of future income taxes as it relates to rate regulated activities. Effective January 1, 2009, future income tax balances arising primarily from property, plant and equipment are recognized, along with offsetting regulatory assets or liabilities to the extent such balances are expected to be included in future rates. Previously, neither the future income tax balance nor the associated regulatory asset or liability would have been recognized.

At December 31, 2008, in the absence of rate regulation, a future income tax liability of $533 million associated primarily with property, plant and equipment would have been recognized.

At December 31, 2008 the Company had recorded net future income tax liabilities of $68 million related to certain regulatory asset and liability deferral accounts identified above. Accumulated future income tax liabilities of $55 million related to the remaining regulatory deferral accounts have not been recognized at December 31, 2008. In the absence of rate regulation, regulatory deferrals would not be recorded nor would the associated future income tax liabilities. As a result of these tax impacts, earnings for the year ended December 31, 2008 would have decreased by $15 million (2007–increased by $62 million).

Allowance for Funds Used During Construction and Other Capitalized Costs

Under the pool method prescribed by certain regulators, it is not possible to identify the carrying value of the equity component of AFUDC or its effect on depreciation. Similarly, gains or losses on the retirement of certain specific fixed assets in any given year cannot be identified or quantified.

Operating Cost Capitalization

EGD entered into a consulting contract relating to asset management initiatives. The majority of the costs are being capitalized to gas mains in accordance with regulatory approval. At December 31, 2009, costs relating to this consulting contract of $112 million (2008–$94 million) were included in property, plant and equipment, and are being depreciated over the average service life of 25 years. In the absence of rate regulation, these costs would be charged to current earnings.

Pension Plans

Prior to January 1, 2009 had pension costs and obligations been recognized at EGD, the net pension asset would have increased by $157 million at December 31, 2008 and earnings would have increased by $3 million for the year ended December 31, 2008 (2007–decreased by $1 million) *(Note 3)*.

Post-Employment Benefits Other than Pensions

Prior to January 1, 2009 had the cost of OPEB been accrued at EGD, the net OPEB liability would have increased by $75 million as at December 31, 2008 and earnings would have decreased by $6 million for the year ended December 31, 2008 (2007–$6 million) *(Note 3)*.

6. Gain on Sale of Investments

December 31,	**2009**	2008	2007
(millions of Canadian dollars)			
NetThruPut (NTP)	**29**	–	–
Oleoducto Central S.A. (OCENSA)	**336**	–	–
Compañía Logística de Hidrocarburos CLH, S.A. (CLH)	**–**	695	–
Other	**–**	5	–
	365	700	–

NTP

On May 1, 2009, the Company sold its investment in NTP, an internet-based exchange facility for physical crude oil products, for proceeds of $32 million. Earnings generated by the NTP investment for the year ended December 31, 2009 were $1 million (2008–$1 million) and are included in the Corporate operating segment.

OCENSA

On March 17, 2009, the Company sold its investment in OCENSA, a crude oil pipeline in Colombia, for proceeds of $512 million (US$402 million). Earnings and cash flows from operating activities generated by this investment for the year ended December 31, 2009 were $7 million (2008–$33 million). Earnings from the OCENSA investment are included in the Natural Gas Delivery and Services operating segment. As a result of the sale of OCENSA, the Company reclassified $20 million of after-tax gains on unrealized cash flow hedges from OCI to earnings in the year ended December 31, 2009.

CLH

On June 17, 2008, the Company sold its 25% investment in CLH for total proceeds of $1,380 million (€876 million), net of transaction costs. The sale of CLH resulted in a gain of $695 million. Earnings generated by the CLH investment for the year ended December 31, 2008 were $25 million (2007–$66 million), and are included in the Natural Gas Delivery and Services operating segment. Operating cash flows generated by the CLH investment for the year ended December 31, 2008 were $12 million (2007–$58 million).

7. Accounts Receivable and Other

December 31,	**2009**	2008
(millions of Canadian dollars)		
Unbilled revenues	**1,018**	751
Trade receivables	**607**	907
Regulatory assets	**181**	138
Taxes receivable	**94**	133
Short-term portion of derivative assets *(Note 23)*	**128**	72
Due from affiliates *(Note 30)*	**336**	19
Prepaid expenses and deposits	**27**	28
Dividends receivable	**14**	13
GST receivable	**–**	75
Other	**79**	186
	2,484	2,322

8. Inventory

December 31, (millions of Canadian dollars)	2009	2008
Natural gas	**492**	674
Other commodities	**292**	171
	784	845

9. Property, Plant and Equipment

December 31, 2009 (millions of Canadian dollars)	Weighted Average Depreciation Rate	Cost	Accumulated Depreciation	Net
Liquids Pipelines				
Pipeline	2.4%	**4,053**	**1,481**	**2,572**
Pumping equipment, buildings, tanks and other	3.5%	**4,029**	**1,065**	**2,964**
Land and right-of-way	2.0%	**118**	**23**	**95**
Under construction	–	**4,129**	**–**	**4,129**
		12,329	**2,569**	**9,760**
Natural Gas Delivery and Services				
Pipeline	3.5%	**1,971**	**570**	**1,401**
Regulating, metering and other equipment	4.0%	**1,204**	**280**	**924**
Gas mains and services	3.4%	**5,133**	**854**	**4,279**
Storage	2.8%	**241**	**43**	**198**
Computer technology	20.6%	**20**	**3**	**17**
Land and right-of-way	4.1%	**103**	**27**	**76**
Under construction	–	**341**	**–**	**341**
		9,013	**1,777**	**7,236**
Sponsored Investments				
Pipeline	4.6%	**1,406**	**368**	**1,038**
Other	6.9%	**139**	**18**	**121**
		1,545	**386**	**1,159**
Corporate				
Wind turbines and other	4.5%	**631**	**35**	**596**
Land and right-of-way	4.0%	**2**	**–**	**2**
Under construction	–	**97**	**–**	**97**
		730	**35**	**695**
		23,617	**4,767**	**18,850**

December 31, 2008	Weighted Average Depreciation Rate	Cost	Accumulated Depreciation	Net
(millions of Canadian dollars)				
Liquids Pipelines				
Pipeline	2.4%	3,162	1,360	1,802
Pumping equipment, buildings, tanks and other	3.7%	2,958	986	1,972
Land and right-of-way	2.5%	70	20	50
Under construction	–	3,857	–	3,857
		10,047	2,366	7,681
Natural Gas Delivery and Services				
Pipeline	3.6%	2,169	589	1,580
Regulating, metering and other equipment	4.4%	1,226	307	919
Gas mains and services	3.7%	5,074	1,401	3,673
Storage	2.7%	239	61	178
Computer technology	19.0%	22	3	19
Land and right-of-way	2.8%	49	11	38
Under construction	–	360	–	360
		9,139	2,372	6,767
Sponsored Investments				
Pipeline	4.4%	1,363	277	1,086
Other	8.1%	112	4	108
		1,475	281	1,194
Corporate				
Wind turbines and other	4.9%	508	17	491
Land and right-of-way	4.0%	2	–	2
Under construction	–	22	–	22
		532	17	515
		21,193	5,036	16,157

10. Joint Ventures

The impact of the Company's joint venture interests on net assets, earnings, cash flows and financial position is summarized below.

		Net Assets	
December 31,	Ownership Interest	**2009**	2008
(millions of Canadian dollars)			
Liquids Pipelines			
Olympic Pipelines	65%	**111**	125
Chicap Pipeline	43.8%	**9**	9
Other	30%-50%	**55**	59
Natural Gas Delivery and Services			
Alliance Pipeline US	50%	**383**	453
Vector Pipeline	60%	**420**	486
Enbridge Offshore Pipelines–various joint ventures	22%-75%	**385**	521
Aux Sable	42.7%	**153**	174
Other	42.7%-70%	**32**	45
Sponsored Investments			
Alliance Pipeline Canada	50%	**676**	688
Other	33%-50%	**46**	48
		2,270	2,608

The following table summarizes the impact of proportionately consolidating the joint ventures to the consolidated financial statements of the Company.

Year ended December 31, (millions of Canadian dollars)	2009	2008	2007
Earnings			
Revenues	**781**	891	844
Commodity costs	**(74)**	(174)	(133)
Operating and administrative	**(226)**	(235)	(208)
Depreciation and amortization	**(171)**	(173)	(153)
Interest expense	**(99)**	(97)	(106)
Other investment income	**10**	13	7
Proportionate share of earnings	**221**	225	251
Cash Flows			
Cash provided by operating activities	**342**	408	312
Cash used in investing activities	**(49)**	(61)	(132)
Cash used in financing activities	**(296)**	(351)	(184)
Proportionate share of decrease in cash and cash equivalents	**(3)**	(4)	(4)

December 31, (millions of Canadian dollars)	2009	2008
Financial Position		
Current assets	**173**	179
Property, plant and equipment, net	**2,769**	3,221
Deferred amounts and other assets	**696**	735
Current liabilities	**(212)**	(177)
Non-recourse long-term debt	**(1,109)**	(1,309)
Other long-term liabilities	**(47)**	(41)
Proportionate share of net assets	**2,270**	2,608

During the year ended December 31, 2009, the Company purchased the additional 50% interest in Starfish Pipeline Company, LLC, increasing its ownership percentage to 100.0%. As the Company established control over the entity effective December 31, 2009, it has consolidated its interest in Starfish Pipeline Company, LLC from that date forward. Prior to December 31, 2009, the entity was classified as a joint venture.

During the year ended December 31, 2008, the Company purchased an additional equity interest in Chicap Pipeline, increasing its ownership percentage to 43.8%. As the Company established joint control over the entity effective October 31, 2008, it has proportionally consolidated its interest in Chicap Pipeline from that date forward. Prior to October 31, 2008, the entity was classified as a long-term investment.

11. Long-Term Investments

December 31,	Ownership Interest	2009	2008
(millions of Canadian dollars)			
Equity Investments			
Sponsored Investments			
The Partnership	27.0%	**1,697**	2,014
Enbridge Energy, L.P. – Series AC	66.7%	**357**	–
Natural Gas Delivery and Services			
Noverco Inc. Common Shares	32.1%	**14**	11
Corporate			
Other	10%–33%	**9**	9
Other Investments			
Natural Gas Delivery and Services			
Noverco Inc. Preferred Shares		**181**	181
Fuel Cell Energy Ltd.		**25**	25
OCENSA		**–**	223
Corporate			
Value Creation Inc.		**29**	29
		2,312	2,492

Equity investments include the unamortized excess of the purchase price over the underlying net book value of the investee's assets at the purchase date of $126 million at December 31, 2009 (2008–$130 million). The excess is attributable to the value of property, plant and equipment within the investees based on estimated fair values at the purchase date and is amortized over the economic life of the assets. During 2009 dividends from equity investments exceeded equity investment earnings by $75 million; whereas during 2008, equity investment earnings exceeded dividends in the year by $10 million.

THE PARTNERSHIP

The Partnership includes the Company's investments in EEP and Enbridge Energy Management, L.L.C. (EEM). The Company has a combined 27.0% ownership in EEP, through a 2.0% general partner interest, a 19.4% interest in Class A units, a 3.3% interest in Class B units and a 2.3% interest in EEP as a result of a 17.2% investment in EEM, which owns 12.6% of EEP through its 100% interest in EEP's i-units. The Company recorded investment income from EEP of $175 million for the year ended December 31, 2009 (2008–$162 million including dilution gains; 2007–$130 million including dilution gains).

Although 82.8% of EEM is widely held, the Company has voting control and therefore consolidates its investment in EEM, including its investment in EEP of $615 million (2008–$691 million). Net of non-controlling interests in EEM, the book value of the Company's investment in EEP is $1,544 million (2008–$1,441 million.)

In October 2009, the Company converted its investment in EEP Class C units into Class A common units. The Class C units converted on a one-for-one basis, resulting in the issuance and receipt of 21,333,273 Class A common units. Prior to the unit conversion, distributions were paid in additional Class C units where Class C units were valued at the market value of Class A units.

In March 2008, EEP issued Class A units and, because Enbridge did not fully participate in this issuance, a dilution gain of $5 million was recognized and Enbridge's ownership interest in EEP decreased from 15.1% to 14.6%. In November 2008, the Company subscribed for 16.3 million Class A common units of EEP for US$510 million increasing its ownership interest from 14.6% to 27.0%.

In the second quarter of 2007, EEP issued Class A and Class C partnership units. As Enbridge did not fully participate in these offerings, dilution gains net of tax and non-controlling interests of $12 million were recognized and Enbridge's ownership interest in the Partnership decreased from 16.6% to 15.1%.

ENBRIDGE ENERGY, L.P.

The Company has a 66.7% interest in the series AC units of EELP, which is constructing the United States segment of the Alberta Clipper project *(Note 30)*.

NOVERCO

The Company owns a preferred share investment in Noverco Inc. (Noverco) of $181 million at December 31, 2009 (2008–$181 million), which is entitled to a cumulative preferred dividend based on the average yield of Government of Canada bonds maturing in greater than 10 years plus 4.34%.

The Company also owns an equity investment in the common shares of Noverco of $14 million at December 31, 2009 (2008–$11 million). Noverco owns an approximate 9.2% (2008–9.3%) reciprocal shareholding in the shares of the Company. As a result, the Company has an indirect pro-rata interest of 2.9% (2008–3.0%) in its own shares. Both the equity investment in Noverco and shareholders' equity have been reduced by the reciprocal shareholding of $154 million at December 31, 2009 (2008–$154 million). Noverco records dividends paid by the Company as dividend income and the Company eliminates these dividends from the earnings of Noverco. The Company records its pro-rata share of dividends paid by the Company to Noverco as a reduction of dividends paid and an increase in the Company's investment in Noverco. In 2009, the Company recorded equity investment earnings of $10 million (2008–$4 million; 2007–$9 million) related to its interest in Noverco.

OCENSA

On March 17, 2009 the Company sold its investment in OCENSA *(Note 6)*.

CORPORATE

The Company reviews the carrying value of its long-term investments on a regular basis as events or changes in circumstances warrant. During 2008, one of the Company's equity investments, N-Solv, a developer of in-situ oil sands extraction technology, failed a key milestone when its planned demonstration pilot plant was terminated. A writedown of $7 million was recognized in the year ended December 31, 2008 to adjust the carrying value of this investment to its fair value of $7 million.

12. Deferred Amounts and Other Assets

December 31,	**2009**	2008
(millions of Canadian dollars)		
Regulatory assets	**1,419**	510
Long-term portion of derivative assets *(Note 23)*	**485**	317
Pension asset *(Note 27)*	**216**	70
Affiliate long-term note receivable, *(Note 30)*	**–**	159
Contractual receivables	**171**	159
Other	**134**	103
	2,425	1,318

At December 31, 2009, deferred amounts of $71 million (2008–$48 million) were subject to amortization and are presented net of accumulated amortization of $34 million (2008–$26 million). Amortization expense in 2009 was $7 million (2008–$5 million; 2007–$4 million).

13. Intangible Assets

December 31, 2009	Weighted Average Amortization Rate	Cost	Accumulated Amortization	Net
(millions of Canadian dollars)				
Software	**17.1%**	**448**	**159**	**289**
Transportation agreements	**4.2%**	**232**	**56**	**176**
Power Purchase Agreements	**4.0%**	**18**	**1**	**17**
Customer lists	**7.1%**	**9**	**3**	**6**
		707	**219**	**488**

December 31, 2008	Weighted Average Amortization Rate	Cost	Accumulated Amortization	Net
(millions of Canadian dollars)				
Software	17.6%	536	303	233
Transportation agreements	4.2%	252	50	202
Power Purchase Agreements	4.0%	16	–	16
Customer lists	7.1%	10	3	7
		814	356	458

Total amortization expense for intangible assets was $44 million for the year ended December 31, 2009 (2008–$58 million; 2007–$43 million). The Company expects aggregate amortization expense for the years ending December 31, 2010 through 2014 of $58 million, $49 million, $42 million, $36 million and $30 million, respectively.

14. Goodwill

	Liquids Pipelines	Natural Gas Delivery and Services	Sponsored Investments	Corporate	Consolidated
(millions of Canadian dollars)					
Balance at December 31, 2007	18	49	308	13	388
Goodwill impairment	–	–	–	(13)	(13)
Foreign exchange and other	4	10	–	–	14
Balance at December 31, 2008	22	59	308	–	389
Goodwill impairment	**–**	**(7)**	**–**	**–**	**(7)**
Foreign exchange and other	**(3)**	**(7)**	**–**	**–**	**(10)**
Balance at December 31, 2009	**19**	**45**	**308**	**–**	**372**

In the fourth quarter of 2009, the Company recognized an impairment of $7 million on goodwill related to Enbridge Electric Connections Inc. within the Natural Gas Delivery and Services segment.

In the fourth quarter of 2008, the Company concluded the goodwill related to Ontario Wind Power, within the Corporate operating segment, was impaired. Accordingly an impairment loss of $13 million was recorded.

15. Accounts Payable and Other

December 31, *(millions of Canadian dollars)*	2009	2008
Operating accrued liabilities	**1,313**	963
Trade payables	**415**	548
Construction payables	**163**	273
Current derivative liabilities *(Note 23)*	**123**	50
Contractor holdbacks	**108**	68
Taxes payable	**103**	273
Security deposits	**60**	123
Other	**178**	113
	2,463	2,411

16. Debt

December 31, *(millions of Canadian dollars)*	Weighted Average Interest Rate	Maturity	2009	2008
Liquids Pipelines				
Debentures	8.20%	2024	**200**	200
Medium-term notes	5.48%	2012–2039	**1,525**	1,125
Southern Lights project financing [1]	2.05%	2014	**1,531**	1,359
Commercial paper and credit facility draws, net			**874**	525
Other [2]			**15**	15
Natural Gas Delivery and Services				
Debentures	11.04%	2010–2024	**385**	485
Medium-term notes	5.77%	2014–2036	**1,795**	1,795
Commercial paper and credit facility draws, net			**512**	883
Corporate				
U.S. dollar term notes [3]	5.48%	2014–2017	**1,151**	1,680
Medium-term notes	5.47%	2010–2039	**2,568**	1,568
Commercial paper and credit facility draws, net [4]			**2,235**	2,034
Deferred debt issue costs and other			**(101)**	(106)
Total Debt			**12,690**	11,563
Current Maturities			**(601)**	(534)
Short-Term Borrowings	0.26%		**(508)**	(874)
Long-Term Debt			**11,581**	10,155

1 *2009–$385 million and US$1,095 million (2008–$318 million and US$850 million).*

2 *Primarily capital lease obligations.*

3 *2009–US$1,100 million (2008–US$1,372 million).*

4 *2009–$1,973 million and US$250 million (2008–$1,189 million and US$690 million).*

Debenture and term note maturities for the years ending December 31, 2010 through 2014 are $600 million, $150 million, $250 million, $200 million and $819 million, respectively. The Company's debentures and term notes bear interest at fixed rates and the interest obligations for the years ending December 31, 2010 through 2014 are $445 million, $407 million, $399 million, $383 million and $360 million, respectively.

INTEREST EXPENSE

Year ended December 31,	2009	2008	2007
(millions of Canadian dollars)			
Debentures and term notes	**484**	404	418
Non-recourse long-term debt	**93**	100	102
Commercial paper and credit facility draws	**71**	100	91
Southern Lights project financing	**45**	28	–
Capitalized	**(96)**	(81)	(61)
	597	551	550

CREDIT FACILITIES

December 31, 2009	Expiry Dates	Total Facilities	Credit Facility Draws [2]	Available
(millions of Canadian dollars)				
Liquids Pipelines	**2011**	**1,300**	**876**	**424**
Natural Gas Delivery and Services	**2010–2011**	**813**	**512**	**301**
Corporate	**2011–2013**	**3,898**	**2,255**	**1,643**
		6,011	**3,643**	**2,368**
Southern Lights project financing [1]	**2014**	**1,796**	**1,531**	**265**
Total Credit Facilities		**7,807**	**5,174**	**2,633**

1 *Total facilities inclusive of $186 million which is available if certain conditions related to the project are met.*

2 *Includes facility draws and commercial paper issuances, net of discount, that are back-stopped by the credit facility.*

Credit facilities carry a weighted average standby fee of 0.39% per annum on the unused portion and draws bear interest at market rates. Certain credit facilities serve as a backstop to the commercial paper programs and the Company has the option to extend the facilities, which are currently set to mature from 2010 to 2014.

Commercial paper and credit facility draws, net of short-term borrowings, of $3,113 million (2008–$2,567 million) are supported by the availability of long-term committed credit facilities and therefore have been classified as long-term debt.

17. Non-Recourse Debt

December 31,	Weighted Average Interest Rate	Maturity	2009	2008
(millions of Canadian dollars)				
Natural Gas Delivery and Services				
Long-term credit facilities [1]		2012	**1**	1
Senior notes [2]	6.77%	2015–2025	**400**	507
Term debt [3]	3.09%	2010–2019	**24**	27
Capital lease obligations	10.45%	2020	**37**	53
Sponsored Investments				
Credit facilities		2011–2012	**222**	174
Medium-term notes	5.25%	2014	**90**	190
Senior notes	6.63%	2015–2025	**708**	679
Fair value increment on senior notes acquired			**33**	38
Deferred debt issue costs and other			**(9)**	(10)
Total Non-Recourse Debt			**1,506**	1,659
Current Maturities			**(113)**	(185)
Non-Recourse Long-Term Debt			**1,393**	1,474

1 *2009–US$1 million (2008–US$1 million).*

2 *2009–US$382 million (2008–US$414 million).*

3 *2009–US$23 million (2008–US$22 million).*

Maturities on non-recourse borrowings for the years ending December 31, 2010 through 2014 are $113 million, $71 million, $77 million, $81 million and $81 million, respectively. The medium-term notes and senior notes bear interest at fixed rates. Interest obligations on non-recourse borrowings for the years ending December 31, 2010 through 2014 are $82 million, $78 million, $72 million, $67 million and $61 million, respectively.

Certain assets of Alliance Pipeline Canada, with a carrying value of $1,055 million, are pledged as collateral to Alliance Pipeline Canada's lenders and to the lenders to Alliance Pipeline US. As well, certain assets of Alliance Pipeline US, with a carrying value of $806 million, are pledged as collateral to Alliance Pipeline US's lenders and to the lenders to Alliance Pipeline Canada.

18. Other Long-Term Liabilities

December 31,	2009	2008
(millions of Canadian dollars)		
Future removal and site restoration reserves *(Note 5)*	**710**	–
Regulatory liabilities	**138**	–
Other post-employment benefit liabilities *(Note 27)*	**110**	22
Derivative liabilities *(Note 23)*	**42**	47
Other	**207**	190
	1,207	259

19. Non-Controlling Interests

December 31,	2009	2008
(millions of Canadian dollars)		
EEM	**424**	481
EIF	**134**	147
EGD Preferred Shares	**100**	100
EGNB	**54**	57
Other	**15**	12
	727	797

Non-controlling interests in EEM represents the 82.8% of the listed shares of EEM not held by the Company.

The Company owns 100% of the outstanding common shares of EGD; however, the four million Cumulative Redeemable EGD Preferred Shares held by third parties are entitled to a claim on the assets of EGD prior to the common shareholder. The fixed yield rate on these preferred shares was 4.93% per annum until July 1, 2009, after which floating adjustable cumulative cash dividends are payable at 80% of the prime rate. The preferred shares have no fixed maturity date. EGD may, at its option, redeem all or a portion of the outstanding shares for $25 per share plus all accrued and unpaid dividends to the redemption date. As at December 31, 2009, no preferred shares have been redeemed.

Non-controlling interests in EIF represents 58.1% of voting units that are held by public unitholders. Non-controlling interests in EGNB represents 27.5% of the limited partnership units held by third parties.

20. Share Capital

The authorized share capital of the Company consists of an unlimited number of common shares with no par value and an unlimited number of preferred shares.

COMMON SHARES

December 31,	2009 Number of Shares	2009 Amount	2008 Number of Shares	2008 Amount	2007 Number of Shares	2007 Amount
(millions of Canadian dollars, number of common shares in millions)						
Balance at beginning of year	**373**	**3,194**	369	3,027	352	2,416
Common shares issued	**–**	**4**	–	–	15	567
Shares issued on exercise of stock options	**1**	**38**	1	36	1	26
Dividend Reinvestment and Share Purchase Plan	**4**	**143**	3	131	1	18
Balance at end of year	**378**	**3,379**	373	3,194	369	3,027

PREFERRED SHARES

The five million 5.5% Cumulative Redeemable Preferred Shares, Series A are entitled to fixed, cumulative, quarterly preferential dividends of $1.375 per share per year. The Company may, at its option, redeem all or a portion of the outstanding preferred shares for $25 per share plus all accrued and unpaid dividends.

EARNINGS PER COMMON SHARE

Earnings per common share is calculated by dividing earnings applicable to common shareholders by the weighted average number of common shares outstanding. The weighted average number of shares outstanding has been reduced by the Company's pro-rata weighted average interest in its own common shares of 11 million (2008–11 million), resulting from the Company's reciprocal investment in Noverco.

The treasury stock method is used to determine the dilutive impact of stock options. This method assumes any proceeds from the exercise of stock options would be used to purchase common shares at the average market price during the period.

December 31,	2009	2008	2007
(number of common shares in millions)			
Weighted average shares outstanding	**364**	360	355
Effect of dilutive options	**2**	3	3
Diluted weighted average shares outstanding	**366**	363	358

For the year ended December 31, 2009, 556,500 anti-dilutive stock options (2008–2,879,800; 2007–1,158,200) with a weighted average exercise price of $40.98 (2008–$40.53; 2007–$38.26) were excluded from the diluted earnings per share calculation.

DIVIDEND REINVESTMENT AND SHARE PURCHASE PLAN

Under the Dividend Reinvestment and Share Purchase Plan, registered shareholders may reinvest dividends in common shares of the Company and make additional optional cash payments to purchase common shares, free of brokerage or other charges. Participants in the Company's Dividend Reinvestment and Share Purchase Plan receive a 2% discount on the purchase of common shares with reinvested dividends.

SHAREHOLDER RIGHTS PLAN

The Shareholder Rights Plan is designed to encourage the fair treatment of shareholders in connection with any takeover offer for the Company. Rights issued under the plan become exercisable when a person and any related parties, acquires or announces its intention to acquire 20% or more of the Company's outstanding common shares without complying with certain provisions set out in the plan or without approval of the Company's Board of Directors. Should such an acquisition occur each rights holder, other than the acquiring person and related parties, will have the right to purchase common shares of the Company at a 50% discount to the market price at that time.

21. Stock Option and Stock Unit Plans

The Company maintains four long term incentive compensation plans: the Incentive Stock Option (ISO) Plan, the Performance Based Stock Option (PBSO) Plan, the Performance Stock Unit (PSU) Plan and the Restricted Stock Unit (RSU) Plan. A maximum of 30 million common shares were reserved for issuance under the 2002 ISO plan, of which 17.5 million have been issued to date. In 2007, a new reserve of 16.5 million shares was approved and established for the 2007 ISO and PBSO plans, of which none have been issued to date. The PSU and RSU plans grant notional units as if a unit was one Enbridge common share and are payable in cash.

INCENTIVE STOCK OPTIONS

Key employees are granted ISOs to purchase common shares at the market price on the grant date. ISOs vest in equal annual installments over a four-year period and expire 10 years after the issue date. Compensation expense recorded for the year ended December 31, 2009 for ISOs is $17 million (2008–$13 million; 2007–$9 million).

Outstanding Incentive Stock Options

December 31,	2009 Number	2009 Weighted Average Exercise Price	2008 Number	2008 Weighted Average Exercise Price	2007 Number	2007 Weighted Average Exercise Price
(options in thousands, exercise price in Canadian dollars)						
Options at beginning of year	**10,650**	**31.05**	9,237	27.24	9,186	24.97
Options granted	**3,028**	**39.62**	2,642	40.54	1,158	38.26
Options exercised	**(1,187)**	**22.01**	(1,178)	21.85	(1,046)	19.21
Options cancelled or expired	**(25)**	**40.65**	(51)	36.83	(61)	32.97
Options at end of year	**12,466**	**34.01**	10,650	31.05	9,237	27.24
Options vested	**6,550**	**28.96**	6,087	25.32	5,865	22.87

The total intrinsic value of ISOs exercised during the year ended December 31, 2009 was $22 million (2008–$23 million; 2007–$19 million) and cash received on exercise was $26 million (2008–$26 million; 2007–$20 million). Intrinsic value represents the difference between the Company's share price and the exercise price, multiplied by the number of options. The total intrinsic value of ISOs outstanding and vested at December 31, 2009 was $81 million (2008–$109 million) and $76 million (2008–$97 million), respectively.

Incentive Stock Option Characteristics

December 31, 2009 Exercise Price Range	Options Outstanding Number	Options Outstanding Weighted Average Remaining Life *(years)*	Options Outstanding Weighted Average Exercise Price	Options Vested Number	Options Vested Weighted Average Remaining Life *(years)*	Options Vested Weighted Average Exercise Price
(options in thousands, exercise price in Canadian dollars)						
10.00–14.99	**111**	**0.3**	**13.09**	**111**	**0.3**	**13.09**
15.00–19.99	**486**	**1.2**	**19.06**	**486**	**1.2**	**19.06**
20.00–24.99	**1,682**	**2.6**	**21.29**	**1,682**	**2.6**	**21.29**
25.00–29.99	**1,025**	**4.0**	**25.72**	**1,025**	**4.0**	**25.72**
30.00–34.99	**1,727**	**6.6**	**32.33**	**1,089**	**5.1**	**31.77**
35.00–39.99	**4,836**	**7.8**	**38.43**	**1,523**	**6.4**	**37.10**
40.00–44.99	**2,599**	**8.1**	**40.86**	**634**	**8.1**	**40.87**
	12,466	6.4	34.01	6,550	4.5	28.96

The total fair value of options vested under the ISO Plan during the year ended December 31, 2009 was $13 million (2008–$9 million).

Weighted average assumptions used to determine the fair value of the ISOs using the Black-Scholes option pricing model are as follows:

Year ended December 31,	2009	2008	2007
Fair value per option *(Canadian dollars)* [1]	**7.12**	6.14	6.16
Valuation assumptions			
Expected option term *(years)* [2]	**6**	6	6
Expected volatility [3]	**28.08%**	18.48%	18.10%
Expected dividend yield [4]	**3.87%**	3.34%	3.22%
Risk-free interest rate [5]	**2.24%**	3.50%	4.11%

1 *Beginning in 2008, options granted to United States employees are based on New York Stock Exchange (NYSE) prices. The option value and assumptions shown for 2009 are based on a weighted average of the United States options and the Canadian options. The fair values per option were $6.73 for Canadian employees and US$6.86 for United States employees.*

2 *The expected option term is based on historical exercise practice.*

3 *Expected volatility is determined with reference to historic daily share price volatility.*

4 *The expected dividend yield is the current annual dividend at the grant date divided by the current stock price.*

5 *The risk-free interest rate is based on the Government of Canada's Canadian Bond Yields and the U.S. Treasury Bond Yields.*

As of December 31, 2009, unrecognized compensation cost related to non-vested share-based compensation arrangements granted under the ISO plan was $14 million. The cost is expected to be fully recognized by December 31, 2012.

PERFORMANCE BASED STOCK OPTIONS

PBSOs are granted to executive officers and become exercisable when both performance targets and time vesting requirements have been met. PBSOs were granted on September 16, 2002, August 15, 2007 and February 19, 2008. The 2008 PBSO grant is included in the 2007 PBSO plan. All performance targets and time vesting requirements for the 2002 PBSO grant have been met. The 2002 PBSO grant will expire on September 16, 2010. The 2007 and 2008 PBSO grants' performance targets are based on the Company's share price. Time vesting requirements for the 2007 PBSO grant are fulfilled evenly over a five-year term, ending August 15, 2012. Under the 2007 PBSO plan, performance targets must be met by February 15, 2014 otherwise the options expire. If targets are met by February 15, 2014, the options are exercisable until August 15, 2015. Compensation expense recorded for the year ended December 31, 2009 for PBSOs was $2 million (2008–$2 million; 2007–$1 million).

Outstanding Performance Based Stock Options

December 31,	2009		2008		2007	
	Number	Weighted Average Exercise Price	Number	Weighted Average Exercise Price	Number	Weighted Average Exercise Price
(options in thousands, exercise price in Canadian dollars)						
Options at beginning of year	**3,738**	**32.72**	3,588	31.92	1,379	23.15
Options granted	**–**	**–**	250	40.42	2,345	36.57
Options exercised	**(343)**	**23.15**	(100)	23.15	(136)	23.15
Options at end of year	**3,395**	**33.69**	3,738	32.72	3,588	31.92
Options vested	**800**	**23.15**	1,143	23.15	1,243	23.15

The total intrinsic value of PBSOs exercised during the year ended December 31, 2009 was $6 million (2008–$2 million; 2007–$2 million) and cash received on exercise was $8 million (2008–$2 million; 2007–$3 million). The total intrinsic value of PBSOs outstanding and vested at December 31, 2009 is $23 million (2008–$32 million) and $14 million (2008–$21 million), respectively.

Performance Based Stock Option Characteristics

December 31, 2009	Options Outstanding			Options Vested		
Exercise Price	Number	Weighted Average Remaining Life *(years)*	Weighted Average Exercise Price	Number	Weighted Average Remaining Life *(years)*	Weighted Average Exercise Price
(options in thousands, exercise price in Canadian dollars)						
23.15	**800**	**0.7**	**23.15**	**800**	**0.7**	**23.15**
36.57	**2,345**	**5.6**	**36.57**	**–**	**–**	**–**
40.42	**250**	**5.6**	**40.42**	**–**	**–**	**–**
	3,395	**4.5**	**33.69**	**800**	**0.7**	**23.15**

The total fair value of options vested under the PBSO Plan during the year ended December 31, 2009 was $2 million (2008–$2 million; 2007–$2 million).

Assumptions used to determine the fair value of the PBSOs at the date of grant using the Bloomberg barrier option valuation model are as follows:

Year ended December 31,	2008	2007
Fair value per option *(Canadian dollars)*	4.82	3.40
Valuation assumptions		
Expected option term *(years)* [1]	8	8
Expected volatility [2]	13.60%	13.60%
Expected dividend yield [3]	3.32%	3.57%
Risk-free interest rate [4]	3.75%	4.38%

1 *Expected option term is based on historical information.*

2 *Expected volatility is determined with reference to 20-day rolling period historic share price information*

3 *The expected dividend yield is the current annual dividend divided by the current stock price.*

4 *The risk-free interest rate is based on the Government of Canada's Canadian Bond Yields and the United States Treasury Bond Yields.*

As of December 31, 2009, unrecognized compensation cost related to non-vested share-based compensation arrangements granted under the PBSO plan was $5 million. The cost is expected to be fully recognized by December 31, 2012.

PERFORMANCE STOCK UNITS

The Company has a PSU Plan for senior officers where cash awards are paid following a three-year performance cycle. Awards are calculated by multiplying the number of units outstanding at the end of the performance period by the Company's weighted average share price and by a performance multiplier. The performance multiplier ranges from zero, if the Company's performance fails to meet threshold performance levels, to a maximum of two, if the Company performs within the highest range of its performance targets. The 2007, 2008 and 2009 grants derive the performance multiplier through a calculation of the Company's price/earnings ratio relative to a specified peer group of companies and the Company's growth in earnings per share, adjusted for non-operating or non-recurring items, relative to targets established at the time of grant.

Compensation expense recorded for the year ended December 31, 2009 for PSUs was $20 million (2008–$13 million; 2007–$3 million). To calculate the 2009 expense, multipliers of two, based upon multiplier estimates at December 31, 2009, were used for each of the 2007, 2008 and 2009 PSU grants.

Outstanding Performance Stock Units

December 31,	2009	2008	2007
Units at beginning of year	**295,428**	267,616	328,716
Units granted	**169,600**	144,300	137,200
Units cancelled	**–**	–	(2,384)
Units matured	**(151,882)**	(129,852)	(209,827)
Dividend reinvestment	**17,270**	13,364	13,911
Units at end of year	**330,416**	295,428	267,616

Of the PSUs outstanding at December 31, 2009, 154,518 units have a performance period ending December 31, 2010 and 175,898 have a performance period ending December 31, 2011. The total intrinsic value of PSUs outstanding at December 31, 2009 is $47 million (2008–$21 million; 2007–$11 million).

RESTRICTED STOCK UNITS

Enbridge has a RSU plan where cash awards are paid to certain non-executive employees of the Company following a 35 month maturity period. RSU holders receive cash equal to the Company's weighted average share price multiplied by the units outstanding on the maturity date. Compensation expense recorded for the year ended December 31, 2009 for RSUs was $23 million (2008–$15 million; 2007–$7 million).

Outstanding Restricted Stock Units

December 31,	2009	2008	2007
Units at beginning of year	**700,034**	456,621	183,253
Units granted	**543,500**	418,700	276,875
Units cancelled	**(18,429)**	(23,352)	(18,627)
Units matured	**(282,656)**	(179,940)	–
Dividend reinvestment	**45,428**	28,005	15,120
Units at end of year	**987,877**	700,034	456,621

The total intrinsic value of RSUs outstanding at December 31, 2009 is $50 million (2008–$29 million; 2007–$18 million).

As of December 31, 2009, unrecognized compensation expense related to non-vested units granted under the PSU and RSU plans was $44 million and is expected to be fully recognized by December 31, 2011.

22. Components of Accumulated Other Comprehensive Income/(Loss)

(millions of Canadian dollars)	Net Investment Hedges	Cumulative Translation Adjustment	Equity Investees	Non-Controlling Interests	Cash Flow Hedges	Total
Balance at January 1, 2007	263	(399)	–	–	–	(136)
Adjustment on adoption	–	–	(57)	26	79	48
Tax impact of adjustment on adoption	–	–	20	–	(20)	–
	–	–	(37)	26	59	48
Changes during the year	194	(534)	(29)	92	95	(182)
Tax impact	(19)	–	9	–	(5)	(15)
	175	(534)	(20)	92	90	(197)
Balance at December 31, 2007	438	(933)	(57)	118	149	(285)
Changes during the year	(180)	658	78	(101)	(175)	280
Tax impact	20	–	(29)	–	47	38
	(160)	658	49	(101)	(128)	318
Balance at December 31, 2008	278	(275)	(8)	17	21	33
Changes during the year	**181**	**(815)**	**(38)**	**72**	**71**	**(529)**
Tax impact	**(30)**	**–**	**14**	**–**	**(31)**	**(47)**
	151	**(815)**	**(24)**	**72**	**40**	**(576)**
Balance at December 31, 2009	**429**	**(1,090)**	**(32)**	**89**	**61**	**(543)**

23. Risk Management

MARKET PRICE RISK

The Company's earnings, cash flows and OCI are subject to movements in foreign exchange rates, interest rates and commodity prices (collectively, market price risk). Formal risk management policies, processes and systems have been designed to mitigate these risks.

Earnings at Risk (EaR), a variant of Value at Risk, is the principal risk management metric used to quantify market price risk at Enbridge. EaR is an objective, statistically derived risk metric that measures the maximum adverse change in projected 12-month earnings that could result from market price risk over a one-month period within a 97.5% confidence interval. The Company's policy is to target a maximum EaR of 5% of earnings. Earnings exposure from market price risk is managed within the overall consolidated EaR limits of the Company. Further, commodity price risk is managed within business unit EaR sub-limits.

The Company calculates EaR using Monte Carlo simulation to produce projections of earnings using a randomly generated series of forecasted market prices and Enbridge's current market exposures. Historical statistical distributions of market prices and the correlation among those market prices are used to generate an entire probability distribution of possible deviations from forecast earnings.

There is currently no uniform industry methodology for estimating EaR. The use of this metric has limitations because it is based on historical correlations and volatilities in commodity prices and assumes future price movements will follow a statistical distribution. Although losses are not expected to exceed the statistically estimated EaR on 97.5% of occasions, losses on the other 2.5% of occasions could be substantially greater than the estimated EaR.

The following summarizes the types of market price risks to which the Company is exposed and the risk management instruments used to mitigate them.

Foreign Exchange Risk

The Company's earnings, cash flows, and OCI are subject to foreign exchange rate variability, primarily arising from its United States dollar denominated subsidiaries. The Company has implemented a policy where it must hedge a minimum level of foreign currency denominated earnings exposures identified over the next five year period. The Company may also hedge anticipated foreign currency denominated purchases or sales, foreign currency denominated debt, as well as certain equity investment balances and net investments in foreign denominated subsidiaries.

The impact of a $0.05 strengthening of the Canadian dollar across the forward curve relative to the United States dollar at December 31, 2009, would have resulted in a $92 million increase (2008–$58 million) to earnings and a $27 million (2008–$19 million) increase to OCI. The foreign exchange sensitivity analysis is limited to changes in the fair value of financial instruments, external debt and loans to foreign operations within the Company that are not denominated in the Company's functional currency and are not considered a net investment. Further, the sensitivity analysis excludes financial instruments that are not monetary items and the impact of the Company's United States dollar denominated self-sustaining subsidiaries on OCI.

Interest Rate Risk

The Company's earnings and cash flows are exposed to short term interest rate variability due to the regular repricing of its variable rate debt. Floating to fixed interest rate swaps and options are used to hedge against the effect of future interest rate movements. The Company has implemented a program to significantly mitigate the volatility of short-term interest rates on interest expense through 2013 at an average rate of 2.2%.

The Company's earnings and cash flows are also exposed to variability in longer term interest rates ahead of anticipated fixed rate debt issuances. Forward starting interest rate swaps are used to hedge against the effect of future interest rate movements. The Company has implemented a hedging program to significantly mitigate its exposure to long term interest rate variability on select forecast term debt issuances through 2013. A total of $2,500 million of future fixed rate term debt issuances have been hedged at an average government bond rate of 4.0%. Further, many of the Company's existing commercial arrangements and certain construction projects provide for the full recovery of financing costs through tolls.

The Company also monitors its debt portfolio mix of fixed and variable rate debt instruments to ensure that the consolidated portfolio of debt stays within its Board of Directors approved policy limit band of a maximum of 25% floating rate debt as a percentage of total debt outstanding.

A 1% increase across the interest rate yield curve would have caused a $2 million increase (2008–nil) in earnings and a $197 million increase (2008–$14 million) in OCI at December 31, 2009 due to the revaluation of interest rate derivatives. If interest rates had been 1% higher during the 12 months ended December 31, 2009, there would have been a $26 million decrease (2008–$24 million) in earnings due to increased interest expense related to the Company's floating rate debt assuming that the variable rate debt outstanding at December 31, 2009 had been outstanding for the entire year, partially offset by an increase in earnings due to increased realized fair value gains on settled interest rate hedges of $15 million (2008–$4 million).

Commodity Price Risk

The Company's earnings and cash flows are exposed to changes in commodity prices as a result of ownership interest in certain assets, as well as through the activities of its energy services subsidiaries. The Company uses natural gas, power, crude oil and NGL derivative instruments to fix a portion of the variable price exposures that may arise from commodity usage, storage, transportation and supply agreements.

The Company has implemented a hedging program to significantly mitigate the volatility from fractionation spreads (natural gas / NGLs) that impact earnings from its ownership in the Aux Sable natural gas processing plant through 2011.

The Company has defined EaR limits for different components of businesses exposed to commodity price risk. The calculation of these limits include physical and financial derivatives as well as physical transportation and storage capacity contracts accounted for as executory contracts in the consolidated financial statements. Positions giving rise to commodity price exposure are monitored against these EaR limits daily. For the year ended December 31, 2009, the average EaR was $29 million (2008–$24 million) and as at December 31, 2009 the Company's EaR was $22 million (2008–$16 million).

TOTAL DERIVATIVE INSTRUMENTS

The following tables summarize the balance sheet location and fair value of the Company's derivative instruments. The Company did not have any outstanding fair value hedges as at December 31, 2009 or December 31, 2008.

December 31, 2009	Derivative Instruments Used as Cash Flow Hedges	Derivative Instruments Used as Net Investment Hedges	Non-Qualifying Derivative Instruments	Total Derivative Instruments
(millions of Canadian dollars)				
Accounts receivable and other *(Note 7)*				
U.S. dollar forwards	4	14	52	70
Interest rate contracts	34	–	2	36
Energy commodity	–	–	19	19
Power commodity	–	–	3	3
	38	14	76	128
Deferred amounts and other *(Note 12)*				
U.S. dollar forwards	25	80	285	390
Interest rate contracts	90	–	–	90
Energy commodity	–	–	1	1
Power commodity	1	–	1	2
Other	1	–	1	2
	117	80	288	485
Accounts payable and other *(Note 15)*				
U.S. dollar forwards	(2)	–	(3)	(5)
Interest rate contracts	(68)	–	–	(68)
Energy commodity	(17)	–	(32)	(49)
Power commodity	–	–	(1)	(1)
	(87)	–	(36)	(123)
Other long-term liabilities *(Note 18)*				
U.S. dollar forwards	(21)	–	–	(21)
Interest rate contracts	(15)	–	–	(15)
Energy commodity	(4)	–	–	(4)
Power commodity	–	–	(2)	(2)
	(40)	–	(2)	(42)
Total net derivative asset /(liability)				
U.S. dollar forwards	6	94	334	434
Interest rate contracts	41	–	2	43
Energy commodity	(21)	–	(12)	(33)
Power commodity	1	–	1	2
Other	1	–	1	2
	28	94	326	448

December 31, 2008	Derivative Instruments Used as Cash Flow Hedges	Derivative Instruments Used as Net Investment Hedges	Non-Qualifying Derivative Instruments	Total Derivative Instruments
(millions of Canadian dollars)				
Accounts receivable and other *(Note 7)*				
U.S. dollar forwards	12	8	–	20
Interest rate contracts	1	–	–	1
Energy commodity	9	–	32	41
Power commodity	1	–	9	10
	23	8	41	72
Deferred amounts and other *(Note 12)*				
U.S. dollar cross currency swaps	26	–	–	26
U.S. dollar forwards	153	63	56	272
Power commodity	7	–	12	19
	186	63	68	317
Accounts payable and other *(Note 15)*				
U.S. dollar forwards	–	–	(14)	(14)
Interest rate contracts	(9)	–	–	(9)
Energy commodity	(22)	–	(4)	(26)
Power commodity	(1)	–	–	(1)
	(32)	–	(18)	(50)
Other long-term liabilities *(Note 18)*				
U.S. dollar forwards	–	–	(8)	(8)
Interest rate contracts	(22)	–	–	(22)
Power commodity	(11)	–	(1)	(12)
Other	(3)	–	(2)	(5)
	(36)	–	(11)	(47)
Total net derivative asset/(liability)				
U.S. dollar cross currency swaps	26	–	–	26
U.S. dollar forwards	165	71	34	270
Interest rate contracts	(30)	–	–	(30)
Energy commodity	(13)	–	28	15
Power commodity	(4)	–	20	16
Other	(3)	–	(2)	(5)
	141	71	80	292

The following table summarizes the maturity and total notional principal or quantity outstanding related to the Company's derivative instruments.

	December 31, 2009		December 31, 2008	
	Maturity	Notional Principal or Quantity Outstanding	Maturity	Notional Principal or Quantity Outstanding
U.S. dollar cross currency swaps *(millions of Canadian dollars)*		–	2013–2022	138
U.S. dollar forwards – purchase *(millions of United States dollars)*	**2010–2019**	**1,078**	2009–2017	1,118
U.S. dollar forwards – sell *(millions of United States dollars)*	**2010–2020**	**3,102**	2009–2021	2,548
Interest rate contracts *(millions of Canadian dollars)*	**2010–2029**	**6,022**	2009–2029	1,164
Energy commodity *(bcf)*	**2010–2011**	**464**	2009–2010	530
Power commodity *(MW/H)*	**2010–2024**	**38**	2009–2024	57

The Company does not have any credit-risk related contingent features associated with its derivative instruments.

The Effect of Derivative Instruments on the Statements of Earnings and Comprehensive Income

The following table presents the effect of cash flow hedges and net investment hedges on the Company's consolidated earnings and consolidated comprehensive income.

Year ended December 31,	2009
(millions of Canadian dollars)	
Amount of Unrealized Gain/(Loss) Recognized in OCI	
Cash Flow Hedges	
U.S. dollar cross currency swaps	**(13)**
U.S. dollar forwards	**(103)**
Interest rate contracts	**73**
Energy commodity	**(41)**
Power commodity	**4**
Other	**3**
Net Investment Hedges	
U.S. dollar forwards	**24**
Total unrealized loss recognized in OCI	**(53)**
Amount of Gain/(Loss) Reclassified from AOCI to Earnings	
U.S. dollar cross currency swaps [1]	**19**
U.S. dollar forwards [1]	**(23)**
Interest rate contracts [2]	**(31)**
Energy commodity [3]	**(78)**
Power commodity [3]	**(1)**
Other	**3**
Total loss reclassified from AOCI to earnings	**(111)**

1 *Gain/(loss) reported within Other Investment Income in the Consolidated Statement of Earnings.*

2 *Loss reported within Interest Expense in the Consolidated Statement of Earnings.*

3 *Loss reported within Commodity costs in the Consolidated Statement of Earnings.*

The Company estimates that $89 million of accumulated other comprehensive loss related to cash flow hedges will be reclassified to earnings in the next 12 months. Actual amounts reclassified to earnings depend on the foreign exchange rates, interest rates and commodity prices when derivative contracts that are currently outstanding mature. For all forecasted transactions, the maximum term over which the Company is hedging exposures to the variability of cash flows is 54 months at December 31, 2009.

During 2008, the Company terminated certain par forward currency exchange instruments for proceeds of $48 million. These instruments hedged US$162 million of the Company's United States dollar self-sustaining operations and were accounted for as net investment hedges with the fair value recorded as long-term assets on the Statement of Financial Position with an equal and offsetting amount recorded in AOCI. No gain or loss related to the terminations will be recorded in the Company's earnings until there is a disposal of or a return of capital on a related investment.

Non-Qualifying Derivatives

The following table presents the unrealized gains and losses associated with changes in the fair value of the Company's non-qualifying derivatives.

Year ended December 31,	**2009**	2008	2007
(millions of Canadian dollars)			
U.S. dollar forwards [1]	**232**	35	–
Interest rate contracts [2]	**2**	–	–
Energy commodity [3]	**(89)**	122	(49)
Power commodity [3]	**1**	–	–
Total unrealized derivative fair value gain	**146**	157	(49)

1 *Gain reported within Other Investment Income in the Consolidated Statement of Earnings.*

2 *Gain reported within Interest Expense in the Consolidated Statement of Earnings.*

3 *Gain/(loss) reported within Commodity costs in the Consolidated Statement of Earnings.*

Additional information regarding the Company's derivative instruments is included in Note 24, Fair Value of Financial Instruments.

LIQUIDITY RISK

Liquidity risk is the risk that the Company will not be able to meet its financial obligations, including commitments and guarantees *(Notes 31 and 32)*, as they become due. In order to manage this risk, the Company forecasts cash requirements over the near and long term to determine whether sufficient funds will be available. The Company's primary sources of liquidity and capital resources are funds generated from operations, the issuance of commercial paper and draws under committed credit facilities and longer term debt which includes debentures and medium-term notes. The Company maintains current shelf prospectuses with the securities regulators, which enables, subject to market conditions, ready access to either the Canadian or United States public capital markets.
In addition, the Company maintains sufficient liquidity through committed credit facilities *(Note 16)* with a diversified group of banks and institutions which, if necessary, enables the Company to fund all anticipated requirements for one year without accessing the capital markets. The Company is in compliance with all the terms and conditions of its committed credit facilities and expects to be in compliance throughout 2010. As a result, all credit facilities are available to the Company and the banks are obligated to fund and have been funding the Company under the terms of the facilities. The Company expects to generate sufficient cash from operations and commercial paper issuances and draws under its committed credit facilities to fund liabilities as they become due, finance planned investing activities and pay common share dividends throughout the year. Additional liquidity, if necessary, is expected to be available through access to the capital markets.

Maturities of Financial Instruments

The Company generally has no financial instruments, other than derivative instruments, maturing beyond one year with the exception of its long-term debt *(Notes 16 and 17)*.

For the years ending December 31, 2010 through 2014, and thereafter, the Company has estimated the following undiscounted cash flows will arise from its derivative instruments based on valuation at the balance sheet date.

	2010	2011	2012	2013	2014	Thereafter
(millions of Canadian dollars)						
Cash inflows	182	106	136	155	86	51
Cash outflows	(167)	(29)	(5)	(7)	(3)	(25)
Net cash flows	15	77	131	148	83	26

CREDIT RISK

Entering into derivative financial instruments can result in exposure to credit risk. Credit risk arises from the possibility that a counterparty will default on its contractual obligations and is limited to those contracts where the Company would incur a loss in replacing the instrument. The Company enters into risk management transactions only with institutions that possess investment grade credit ratings. Credit risk relating to derivative counterparties is mitigated by credit exposure limits and contractual requirements, frequent assessment of counterparty credit ratings and netting arrangements. At December 31, 2009, the Company has a maximum exposure to credit risk of $517 million related to its derivative counterparties.

Credit risk also arises from trade and other long-term receivables, and is mitigated through credit exposure limits and contractual requirements, assessment of credit ratings and netting arrangements. Credit risk in the Natural Gas Delivery and Services segment is mitigated by the large and diversified customer base and the ability to recover an estimate for doubtful accounts through the ratemaking process. The Company actively monitors the financial strength of large industrial customers and, in select cases, has obtained additional security to minimize the risk of default on receivables. Generally, the Company classifies and provides for receivables older than 30 days as past due. The maximum exposure to credit risk related to non-derivative financial assets is their carrying value, as disclosed in Note 24, Fair Value of Financial Instruments.

The change in allowance for doubtful accounts in respect of accounts receivable is detailed below.

Year ended December 31,	**2009**	2008
(millions of Canadian dollars)		
Balance at beginning of year	**(69)**	(55)
Additional allowance	**(29)**	(37)
Amounts used	**24**	23
Balance at end of year	**(74)**	(69)

The allowance for doubtful accounts is determined based on collection history. When the Company has determined that further collection efforts are unlikely to be successful, amounts charged to the allowance for doubtful accounts are applied against the impaired accounts receivable.

24. Fair Value of Financial Instruments

The following table summarizes the Company's financial instrument carrying and fair values and provides a reconciliation to the Consolidated Statements of Financial Position.

December 31, 2009	Held for Trading	Available for Sale	Loans and Receivables	Held to Maturity	Other Financial Liabilities	Qualifying Derivatives	Non-Financial Instruments	Total	Fair Value [1]
(millions of Canadian dollars)									
Assets									
Cash and cash equivalents	**327**	–	–	–	–	–	–	**327**	**327**
Accounts receivable and other	**76**	–	**2,054**	–	–	**52**	**302**	**2,484**	**2,182**
Long-term investments	–	**54**	**6**	**181**	–	–	**2,071**	**2,312**	**187**
Deferred amounts and other assets	**288**	–	–	–	–	**197**	**1,940**	**2,425**	**485**
Liabilities									
Short-term borrowings	–	–	–	–	**508**	–	–	**508**	**508**
Accounts payable and other	**36**	–	–	–	**2,177**	**87**	**163**	**2,463**	**2,300**
Interest payable	–	–	–	–	**104**	–	–	**104**	**104**
Long-term debt	–	–	–	–	**12,283**	–	**(101)**	**12,182**	**13,450**
Non-recourse long-term debt	–	–	–	–	**1,515**	–	**(9)**	**1,506**	**1,573**
Other long-term liabilities	**2**	–	–	–	–	**40**	**1,165**	**1,207**	**42**

December 31, 2008	Held for Trading	Available for Sale	Loans and Receivables	Held to Maturity	Other Financial Liabilities	Qualifying Derivatives	Non-Financial Instruments	Total	Fair Value [1]
(millions of Canadian dollars)									
Assets									
Cash and cash equivalents	542	–	–	–	–	–	–	542	542
Accounts receivable and other	41	–	1,869	–	–	31	381	2,322	1,948
Long-term investments	–	54	167	405	–	–	1,866	2,492	492
Deferred amounts and other assets	68	–	–	–	–	249	1,001	1,318	317
Liabilities									
Short-term borrowings	–	–	–	–	874	–	–	874	874
Accounts payable and other	18	–	–	–	1,965	32	396	2,411	2,015
Interest payable	–	–	–	–	102	–	–	102	102
Long-term debt	–	–	–	–	10,795	–	(106)	10,689	11,173
Non-recourse long-term debt	–	–	–	–	1,669	–	(10)	1,659	1,672
Other long-term liabilities	11	–	–	–	–	36	212	259	47

1 *Fair value does not include non-financial instruments, which includes investments accounted for under the equity method, and available for sale equity instruments held at cost that do not trade on an actively quoted market.*

The fair value of financial instruments reflects the Company's best estimates of market value based on generally accepted valuation techniques or models and supported by observable market prices and rates. When such values are not available, the Company uses discounted cash flow analysis from applicable yield curves based on observable market inputs to estimate fair value. The fair value of financial instruments other than derivatives represents the amounts that would have been received from or paid to counterparties to settle these instruments at the reporting date.

The fair value of cash and cash equivalents and short-term borrowings approximates their carrying value due to their short-term maturities. The fair value of the Company's long-term investments, other than those classified as available for sale, approximates their carrying value due to interest terms which approximate floating market rates. The fair value of the Company's long-term debt and non-recourse long-term debt is based on quoted market prices for instruments of similar yield, credit risk and tenure. The fair value of other financial assets and liabilities other than derivative instruments approximate their cost due to the short period to maturity. Changes in the fair value of financial liabilities other than derivative instruments are due primarily to fluctuations in interest rates and time value.

FAIR VALUE OF DERIVATIVES

The Company categorizes its derivative assets and liabilities measured at fair value into one of three different levels depending on the observability of the inputs employed in the measurement.

Level 1

Level 1 includes assets and liabilities measured at fair value based on unadjusted quoted prices for identical assets and liabilities in active markets that are accessible at the measurement date. An active market for an asset or liability is considered to be a market where transactions occur with sufficient frequency and volume to provide pricing information on an ongoing basis. The Company's Level 1 instruments consist primarily of exchange-traded derivative instruments used to mitigate the risk of crude oil price fluctuations in its Liquids Pipelines segment and commodity marketing businesses.

Level 2

Level 2 includes valuations determined using directly or indirectly observable inputs other than quoted prices included within Level 1. Derivative instruments in this category are valued using models or other industry standard valuation techniques derived from observable market data. Such valuation techniques include inputs such as quoted forward prices, time value, volatility factors and broker quotes that can be observed or corroborated in the market for the entire duration of the derivative instrument. Instruments valued using Level 2 inputs include non-exchange traded derivatives such as over the counter foreign exchange forward and cross currency swap contracts, interest rate swaps, physical forward commodity contracts as well as commodity swaps and options for which observable inputs can be obtained. These instruments are used primarily in the Company's commodity marketing businesses and the Corporate segment.

Level 3

Level 3 includes valuations based on inputs which are less observable, unavailable or where the observable data does not support a significant portion of the instruments' fair value. Generally, Level 3 valuations are longer dated transactions, occur in less active markets, occur at locations where pricing information is not available or have no binding broker quote to support Level 2 classification. The Company has developed methodologies, benchmarked against industry standards, to determine fair value for these contracts based on extrapolation of observable future prices and rates. Instruments valued using Level 3 inputs include long dated derivative power, NGL and natural gas contracts in its Liquids Pipelines segment and commodity marketing businesses.

When possible the estimated fair value is based on quoted market prices and, if not available, estimates from third party brokers. For non-exchange traded derivatives classified in Levels 2 and 3, the Company uses standard valuation techniques to calculate fair value. These methods include discounted cash flows for forwards and swaps and Black-Scholes pricing models for options. Depending on the type of derivative and nature of the underlying risk, primary inputs to these techniques include observable market prices (interest, foreign exchange and commodity) and volatility. The Company uses inputs and data used by willing market participants when valuing derivatives and considers its own credit default swap spread as well as those of its counterparties in its determination of fair value. Where possible the Company uses observable inputs.

The Company has categorized its derivative assets and liabilities measured at fair value as follows:

December 31, 2009	Level 1	Level 2	Level 3	Total
(millions of Canadian dollars)				
Financial assets: [1]				
Current derivative assets	**2**	**84**	**42**	**128**
Long-term derivative assets	**–**	**481**	**4**	**485**
Financial liabilities:				
Current derivative liabilities	**(2)**	**(68)**	**(53)**	**(123)**
Long-term derivative liabilities	**–**	**(39)**	**(3)**	**(42)**
Total net derivative asset/(liability)	**–**	**458**	**(10)**	**448**

1 *Excludes cash and cash equivalents.*

December 31, 2008	Level 1	Level 2	Level 3	Total
(millions of Canadian dollars)				
Financial assets: [1]				
Current derivative assets	10	9	53	72
Long-term derivative assets	–	301	16	317
Financial liabilities:				
Current derivative liabilities	–	(44)	(6)	(50)
Long-term derivative liabilities	–	(37)	(10)	(47)
Total net derivative asset	10	229	53	292

1 *Excludes cash and cash equivalents.*

Changes in net fair value of derivative assets and liabilities classified as Level 3 in the fair value hierarchy were as follows:

Year ended December 31,	**2009**	2008
(millions of Canadian dollars)		
Level 3 net derivative asset at beginning of year	**53**	(37)
Total gains/(losses), realized and unrealized		
Included in earnings	**(9)**	34
Included in OCI	**7**	2
Purchases, issuances and settlements	**(61)**	54
Level 3 net derivative asset/(liability) at end of year	**(10)**	53

25. Capital Disclosures

The Company defines capital as shareholders' equity (excluding AOCI and reciprocal shareholdings), long-term debt (excluding non-recourse debt and transaction costs), short-term borrowings and non-controlling interests less cash and cash equivalents (excluding cash and cash equivalents from joint ventures and other interests not exclusively controlled by the Company). Non-recourse debt, including debt consolidated proportionately from joint venture interests, is excluded from the Company's definition of capital as it is not controlled or managed exclusively by the Company.

The Company's capital is calculated as follows:

December 31,	**2009**	2008
(millions of Canadian dollars)		
Short-term borrowings	**508**	874
Long-term debt (includes current portion)	**12,283**	10,795
Non-controlling interests	**727**	797
Shareholders' equity [1]	**7,958**	6,740
Cash and cash equivalents	**(258)**	(469)
	21,218	18,737

1 *Excludes AOCI and reciprocal shareholdings.*

The Company's objectives when managing capital are to maintain flexibility among: enabling its businesses to operate at the highest efficiency; providing liquidity for growth opportunities; and providing acceptable returns to shareholders. These objectives are primarily met through maintenance of an investment grade credit rating, which provides access to lower cost capital. Capital is available generally through the issuance of both short and long-term debt and equity.

The Company manages its capital by monitoring its debt to debt plus equity ratio (excluding non-recourse debt), with a target range of 60% to 70%, to meet its capital management objectives. The debt to capitalization ratio at December 31, 2009, including short-term borrowings but excluding non-recourse short and long-term debt, was 63.6% compared with 63.6% at the end of 2008.

The Company must adhere to covenants in its credit facilities that are used to backstop its commercial paper program. These covenants include maintaining a minimum Consolidated Shareholders' Equity balance of $1,000 million or greater and an unconsolidated debt to unconsolidated shareholders' equity ratio of less than 1.5. As at December 31, 2009, the Company was in compliance with these covenants.

Under terms of the Company's Trust Indenture, in order to continue to issue long-term debt, the Company must maintain a ratio of consolidated funded obligations (essentially all debt except non-recourse debt) to total consolidated capitalization of less than 75%. Total consolidated capitalization consists of shareholders' equity, long-term debt, non-controlling interests and future income tax. As at December 31, 2009, the Company was in compliance with this covenant.

26. Income Taxes

INCOME TAX RATE RECONCILIATION

Year ended December 31, *(millions of Canadian dollars)*	2009	2008	2007
Earnings before income taxes	**1,868**	1,837	916
Combined statutory income tax rate	**30.5%**	31.3%	33.9%
Income taxes at statutory rate	**570**	575	311
Increase/(decrease) resulting from:			
Tax rates and legislated tax changes	**(58)**	(11)	(63)
Future income taxes related to regulated operations	**(68)**	(15)	(6)
Non-taxable items, net	**11**	2	(19)
Higher/(lower) foreign tax rates	**(61)**	3	(6)
Sale of investments	**(99)**	(82)	–
Other	**11**	37	(8)
Income Taxes	**306**	509	209
Effective income tax rate	**16.4%**	27.7%	22.8%

COMPONENTS OF FUTURE INCOME TAXES

December 31, *(millions of Canadian dollars)*	2009	2008
Net Future Income Tax Liabilities/(Assets)		
Differences in accounting and tax bases of property, plant and equipment	**1,346**	790
Differences in accounting and tax bases of investments	**407**	452
Regulatory assets	**319**	–
Financial instruments	**121**	(1)
Loss carryforwards	**(138)**	(150)
Other	**29**	22
Net Future Income Tax Liability	**2,084**	1,113

Net future income tax liability of $2,084 million (2008–$1,113 million) includes future income tax liabilities of $2,211 million (2008–$1,291 million) net of future income tax assets of $127 million (2008–$178 million).

At December 31, 2009, the Company has recognized the benefit of unused tax loss carryforwards of $425 million (2008–$452 million) of which $421 start to expire in 2019 and beyond.

GEOGRAPHICAL COMPONENTS OF PRETAX EARNINGS AND INCOME TAXES

Year ended December 31,	**2009**	2008	2007
(millions of Canadian dollars)			
Earnings before income taxes			
Canada	**954**	624	511
United States	**334**	419	210
Other	**580**	794	195
	1,868	1,837	916
Current income taxes			
Canada	**49**	141	152
United States	**35**	43	12
Other	**4**	67	4
	88	251	168
Future income taxes			
Canada	**117**	92	(36)
United States	**101**	166	77
	218	258	41
Current and future income taxes	**306**	509	209

27. Post-Employment Benefits

PENSION PLANS

The Company has three basic pension plans which provide either defined benefit or defined contribution pension benefits, or both, to employees of the Company. The Liquids Pipelines and Natural Gas Delivery and Services pension plans (collectively, the Canadian Plans) provide Company funded defined benefit pension and/or defined contribution benefits to Canadian employees of Enbridge. The Enbridge United States pension plan (the United States Plan) provides Company funded defined benefit pension benefits for United States based employees. The Company has four supplemental pension plans which provide pension benefits in excess of the basic plans for certain employees.

The measurement date used to determine the plan assets and the accrued benefit obligation was September 30, 2009 for the Canadian Plans and December 31, 2009 for the United States Plan.

Defined Benefit Plans

Benefits payable from the defined benefit plans are based on members' years of service and final average remuneration. These benefits are partially inflation indexed after a member's retirement. Contributions by the Company are made in accordance with independent actuarial valuations and are invested primarily in publicly-traded equity and fixed income securities. The effective dates of the most recent actuarial valuations and the next required actuarial valuations for the basic plans are as follows:

	Effective Date of Most Recently Filed Actuarial Valuation	Effective Date of Next Required Actuarial Valuation
Canadian Plans	December 31, 2006	December 31, 2009[1]
United States Plan	December 31, 2008	December 31, 2009

1 The December 31, 2009 valuation will be filed in mid-2010.

The defined benefit pension plan costs have been determined based on management's best estimates and assumptions of the rate of return on pension plan assets, rate of salary increases and various other factors including mortality rates, terminations and retirement ages.

Defined Contribution Plans

Contributions are generally based on the employee's age, years of service and remuneration. For defined contribution plans, benefit costs equal amounts required to be contributed by the Company.

Post-Employment Benefits Other than Pensions

OPEB primarily include supplemental health, dental, health spending account and life insurance coverage for qualifying retired employees.

DEFINED BENEFIT PLANS

The following tables detail the changes in the benefit obligation, the fair value of plan assets and the recorded asset or liability for the Company's defined benefit pension plans and OPEB plans using the accrual method.

	Pension Benefits		OPEB	
December 31,	**2009**	2008	**2009**	2008
(millions of Canadian dollars)				
Change in Accrued Benefit Obligation				
Benefit obligation at beginning of year	**1,075**	1,100	**179**	183
Service cost	**53**	53	**4**	5
Interest cost	**71**	65	**11**	11
Amendments	**–**	(4)	**–**	–
Employees' contributions	**–**	–	**1**	1
Actuarial gain	**(13)**	(125)	**(1)**	(27)
Benefits paid	**(51)**	(46)	**(8)**	(7)
Effect of foreign exchange rate changes	**(16)**	32	**(16)**	13
Benefit obligation at end of year	**1,119**	1,075	**170**	179
Change in Plan Assets				
Fair value of plan assets at beginning of year	**1,141**	1,310	**46**	48
Actual return on plan assets	**51**	(180)	**6**	(12)
Employer's contributions	**44**	33	**9**	8
Employees' contributions	**–**	–	**1**	1
Benefits paid	**(51)**	(46)	**(8)**	(7)
Other	**(1)**	(1)	**(8)**	–
Effect of foreign exchange rate changes	**(17)**	25	**(8)**	8
Fair value of plan assets at end of year	**1,167**	1,141	**38**	46
Funded Status				
Benefit obligation	**(1,119)**	(1,075)	**(170)**	(179)
Fair value of plan assets	**1,167**	1,141	**38**	46
Overfunded/(Underfunded) status at end of year	**48**	66	**(132)**	(133)
Contribution after measurement date	**14**	2	**1**	1
Unamortized prior service cost	**6**	7	**–**	–
Unamortized transitional obligation/(asset)	**(13)**	(15)	**9**	11
Unamortized net loss	**161**	167	**12**	24
Net amount recognized on an accrual basis at end of year	**216**	227	**(110)**	(97)
Adjustment to cash basis for amounts in EGD [1]	**–**	(157)	**–**	75
Net amount recognized in the Consolidated Statement of Financial Position at end of year [1]	**216**	70	**(110)**	(22)
Presented as follows:				
Deferred Amounts and Other *(Note 12)*	**216**	70	**–**	–
Other Long-Term Liabilities *(Note 18)*	**–**	–	**(110)**	(22)

1 Prior to January 1, 2009, the Company recognized pension benefit costs related to its regulated EGD pension plan on the cash basis. As a result, this amount was not recognized in the Consolidated Statements of Financial Position (Note 3).

The weighted average assumptions made in the measurement of the projected benefit obligations of the pension plans and OPEB are as follows:

	Pension Benefits			OPEB		
Year ended December 31,	**2009**	2008	2007	**2009**	2008	2007
Discount rate	**6.46%**	6.59%	5.65%	**6.28%**	6.42%	5.71%
Average rate of salary increases	**3.73%**	5.00%	5.00%			

Net Benefit Costs Recognized

	Pension Benefits			OPEB		
Year ended December 31,	**2009**	2008	2007	**2009**	2008	2007
(millions of Canadian dollars)						
Benefits earned during the year	**53**	53	47	**4**	5	5
Interest cost on projected benefit obligations	**71**	65	58	**11**	11	10
Actual return on plan assets	**(51)**	180	(105)	**(6)**	12	(2)
Difference between actual and expected return on plan assets	**(27)**	(273)	20	**3**	(15)	–
Amortization of prior service costs	**2**	2	2	**–**	–	–
Amortization of transitional obligation	**(2)**	(2)	(2)	**1**	1	1
Amortization of actuarial loss	**21**	4	12	**1**	1	2
Amount charged to EEP [1]	**(20)**	(8)	(7)	**(5)**	(3)	(4)
Net defined benefit costs on an accrual basis	**47**	21	25	**9**	12	12
Adjustment to cash basis for amounts in EGD [2]	**–**	(3)	(1)	**–**	6	6
Defined contribution benefit costs	**4**	4	4	**–**	–	–
Net benefit cost recognized in the Consolidated Statements of Earnings	**51**	22	28	**9**	18	18

1 *EEP does not have employees and uses the services of the Company for managing and operating its businesses. EEP is charged an amount, measured at cost, for pension benefits and OPEB.*

2 *Prior to January 1, 2009, the Company recognized pension benefit costs related to its regulated EGD pension plan on the cash basis (Note 3).*

The weighted average assumptions made in the measurement of the cost of the pension plans and OPEB are as follows:

	Pension Benefits			OPEB		
Year ended December 31,	**2009**	2008	2007	**2009**	2008	2007
Discount rate	**6.59%**	5.65%	5.27%	**6.42%**	5.71%	5.37%
Average rate of return on pension plan assets	**7.30%**	7.30%	7.31%	**6.09%**	6.00%	4.50%
Average rate of salary increases	**5.00%**	5.00%	5.00%			

MEDICAL COST TRENDS

The assumed rates for the next year used to measure the expected cost of benefits are as follows:

	Medical Cost Trend Rate Assumption for Next Fiscal Year	Ultimate Medical Cost Trend Rate Assumption	Year in which Ultimate Medical Cost Trend Rate Assumption is Achieved
Canadian Plans			
Drugs	9.4%	4.5%	2029
Other Medical and Dental	4.5%	4.5%	2009
United States Plan	8.0%	4.5%	2029

A 1% increase in the assumed medical and dental care trend rate would result in an increase of $23 million in the accumulated post-employment benefit obligations and an increase of $2 million in benefit and interest costs.

A 1% decrease in the assumed medical and dental care trend rate would result in a decrease of $19 million in the accumulated post-employment benefit obligations and a decrease of $2 million in benefit and interest costs.

PLAN ASSETS

Major Categories of Plan Assets

Plan assets are invested in a diversified manner, primarily in readily marketable investments including equity and fixed income securities.

As at December 31, 2009, the pension benefits assets were invested 54.7% (2008–57.3%) in equity securities, 34.0% (2008–35.1%) in fixed income securities and 11.3% (2008–7.6%) in other. The OPEB assets were invested 60.5% (2008–58.0%) in equity securities and 39.5% (2008–42.0%) in fixed income securities.

December 31, 2009	Level 1 [1]	Level 2 [2]	Level 3 [3]	Total
(millions of Canadian dollars)				
Pension Benefits:				
Cash and cash equivalents	65	–	–	65
Fixed income securities:				
Canadian government bonds	–	82	–	82
Corporate bonds and debentures	4	–	–	4
Canadian corporate bond index fund	131	–	–	131
Canadian government bond index fund	137	–	–	137
United States debt index fund	43	–	–	43
Equity:				
Canadian equity securities	150	–	–	150
Canadian equity funds	89	–	–	89
United States equity funds	117	–	–	117
Global equity funds	127	117	–	244
Private equity investment [4]	–	–	37	37
Exchange-traded foreign currency derivatives	1	–	–	1
Other:				
Refundable taxes receivable [5]	–	–	62	62
Other net receivables/(payables)	–	–	–	5
	864	199	99	1,167
OPEB:				
Fixed income securities:				
United States government and government agency bonds	–	15	–	15
Equity:				
Global equity funds	23	–	–	23
	23	15	–	38

1 *Level 1 assets include assets with quoted prices in active markets for identical assets.*

2 *Level 2 assets include assets with significant observable inputs.*

3 *Level 3 assets include assets with significant unobservable inputs.*

4 *The fair value of the investment in United States Limited Partnership – Global Infrastructure Fund is established through the use of valuation models.*

5 *The fair value of refundable taxes receivable approximates carrying value due to the nature of the receivable and the short period to maturity.*

Changes in the net fair value of plan assets classified as Level 3 in the fair value hierarchy were as follows.

	Private Equity Investment	Refundable Taxes Receivable
Balance at beginning of year	19	55
Total gains/(losses), unrealized	(2)	–
Purchases, issuances, settlements	20	7
Balance at end of year	37	62

The Company manages the investment risk of its pension funds by setting a long-term asset mix policy for each plan after consideration of: (i) the nature of pension plan liabilities; (ii) the investment horizon of the plan; (iii) the going concern and solvency funded status and cash flow requirements of the plan; (iv) the operating environment and financial situation of the Company and its ability to withstand fluctuations in pension contributions; and (v) the future economic and capital markets outlook with respect to investment returns, volatility of returns and correlation between assets. The overall expected rate of return is based on the asset allocation targets with estimates for returns on equity and debt securities based on long-term expectations.

Target Mix for Plan Assets

	Liquids Pipelines Pension Plan	Natural Gas Delivery and Services Pension Plan	Enbridge United States Pension Plan
Equity securities	62.5%	52.5%	57.5%
Fixed income securities	32.5%	42.5%	37.5%
Other	5.0%	5.0%	5.0%

Expected Rate of Return on Plan Assets

	Pension Benefits		OPEB	
Year ended December 31,	**2009**	2008	**2009**	2008
Canadian Plans	**7.25%**	7.25%	**6.00%**	6.00%
United States Plan	**7.75%**	7.75%	**6.00%**	6.00%

PLAN CONTRIBUTIONS BY THE COMPANY

	Pension Benefits		OPEB	
Year ended December 31,	**2009**	2008	**2009**	2008
(millions of Canadian dollars)				
Total contributions	**44**	33	**9**	8
Contributions expected to be paid in 2010	**66**		**8**	

BENEFITS EXPECTED TO BE PAID BY THE COMPANY

Year ended December 31,	2010	2011	2012	2013	2014	2015–2019
(millions of Canadian dollars)						
Expected future benefit payments	61	63	66	70	73	428

28. Other Investment Income

Year ended December 31, (millions of Canadian dollars)	2009	2008	2007
Net foreign currency gains	**444**	43	26
Allowance for equity funds used during construction (AEDC)	**135**	59	15
Interest income on affiliate loans	**38**	34	33
Noverco preferred dividends income	**15**	16	16
Hurricane insurance recoveries	**13**	–	14
OCENSA investment income	**6**	23	25
Gain on reduction of EEP ownership interest	**–**	13	34
Other	**27**	10	32
	678	198	195

29. Changes in Operating Assets and Liabilities

Year ended December 31, (millions of Canadian dollars)	2009	2008	2007
Accounts receivable and other	**76**	186	(492)
Inventory	**99**	(135)	160
Deferred amounts and other assets	**(349)**	95	(135)
Accounts payable and other	**134**	(115)	415
Interest payable	**2**	9	(6)
Other long-term liabilities	**281**	(66)	62
	243	(26)	4

30. Related Party Transactions

All related party transactions are provided in the normal course of business and, unless otherwise noted, measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties.

EEP, an equity investee, does not have employees and uses the services of the Company for managing and operating its businesses. Vector Pipeline, a joint venture, contracts the services of Enbridge to operate the pipeline. Amounts for these services, which are charged at cost in accordance with service agreements, are as follows.

Year ended December 31, (millions of Canadian dollars)	2009	2008	2007
EEP	**342**	302	267
Vector Pipeline	**6**	6	5
	348	308	272

At December 31, 2009, the Company has accounts receivable of $38 million (2008–$41 million) from EEP and $1 million (2008–$1 million) from Vector Pipeline.

The Company has provided EEP with an unsecured revolving credit agreement for general liquidity support. The credit facility provides for a maximum principle amount of US$500 million for a three-year term maturing in December 2010. At December 31, 2009 and 2008, there were no amounts outstanding on this facility.

EGD, a subsidiary of the Company, has contracts for gas transportation services from Alliance Pipeline Canada and US and Vector Pipeline. EGD is charged market prices for these services as follows.

Year ended December 31,	**2009**	2008	2007
(millions of Canadian dollars)			
Alliance Pipeline Canada	**24**	24	21
Alliance Pipeline US	**18**	17	15
Vector Pipeline	**29**	27	25
	71	68	61

Enbridge Gas Services (US) Inc., a subsidiary of the Company, purchases and sells gas at prevailing market prices with Enbridge Marketing (US) Inc., a subsidiary of EEP. Amounts charged/(recovered) are as follows.

Year ended December 31,	**2009**	2008	2007
(millions of Canadian dollars)			
Purchases	**16**	52	43
Sales	**(6)**	(7)	(4)
	10	45	39

Enbridge Gas Services Inc. and Enbridge Gas Services (US) Inc., subsidiaries of the Company, have transportation commitments, measured at market value, through 2015 on Alliance Pipeline Canada and Vector Pipeline. Amounts charged are as follows.

Year ended December 31,	**2009**	2008	2007
(millions of Canadian dollars)			
Alliance Pipeline Canada	**9**	9	8
Alliance Pipeline US	**7**	7	7
Vector Pipeline	**16**	16	16
	32	32	31

Tidal Energy Marketing Inc., a subsidiary of the Company, purchases and sells commodities at prevailing market prices with EEP and a subsidiary of EEP as follows.

Year ended December 31,	**2009**	2008	2007
(millions of Canadian dollars)			
Purchases	**80**	24	5
Sales	**(7)**	(9)	(6)
	73	15	(1)

CustomerWorks Limited Partnership (CustomerWorks), a joint venture, provided customer care services to EGD under an agreement having a five-year term which expired in 2007 and was not renewed. EGD was charged market prices for these services. CustomerWorks also rented an automated billing system from Enbridge Commercial Services Inc. (ECS), a subsidiary of the Company. Amounts charged by/(to) CustomerWorks are as follows:

Year ended December 31,	**2009**	2008	2007
(millions of Canadian dollars)			
EGD	**–**	–	26
ECS	**(2)**	(2)	(2)
	(2)	(2)	24

ALBERTA CLIPPER PROJECT

In July 2009, the Company committed to fund 66.7% of the cost to construct the United States segment of the Alberta Clipper Project. The total cost of the United States segment, which is expected to be ready for service on April 1, 2010, is estimated at US$1,300 million, with total expenditures to date of US$900 million.

The Company is funding 66.7% of the project's equity requirements through EELP, an equity investee. The Company has provided a $282 million (US$270 million) loan to EEP for debt financing related to the construction. At December 31, 2009, this amount is included in Accounts Receivable and Other. The loan, denominated in United States dollars, bears interest based on variable short-term rates.

In August 2008, the Company transferred $23 million, measured at market value, of 36 inch diameter line pipe to EEP for use in constructing the United States segment of the Alberta Clipper Project.

SPEARHEAD NORTH PIPELINE

In May 2009, the Company sold a section of the Spearhead Pipeline to its affiliate EEP for proceeds of US$75 million. This related party transaction has been recorded at the exchange amount which was equal to the carrying amount.

SOUTHERN LIGHTS PROJECT

In February 2009, as part of its Southern Lights Pipeline Project, the Company transferred the United States section of a newly constructed light sour pipeline to EEP in exchange for a pipeline referred to as Line 13. This non-monetary transaction has been recorded at the carrying amount.

In connection with the exchange discussed above, EEP entered into an arrangement to lease Line 13 from the Company for monthly payments of US$2 million to ensure adequate southbound pipeline capacity prior to the completion of the Alberta Clipper Project. The lease arrangement was effective in February 2009 and can be terminated at any time with written notice.

LONG-TERM RECEIVABLE FROM AFFILIATE

The affiliate long-term note receivable of $159 million (US$130 million) as at December 31, 2008, included in Deferred Amounts and Other Assets, was repaid by EEP in November 2009. Interest income for the year ended December 31, 2009 related to the note receivable was $11 million (2008–$12 million; 2007–$10 million).

31. Commitments and Contingencies

COMMITMENTS

The Company has signed contracts for the purchase of services, pipe and other materials totaling $697 million which are expected to be paid within the next 5 years.

ENBRIDGE GAS DISTRIBUTION INC.

Bloor Street Incident

EGD was charged under both the Ontario Technical Standards and Safety Act (TSSA) and the Ontario Occupational Health and Safety Act (OHSA) in connection with an explosion that occurred on Bloor Street West in Toronto in April 2003. In October 2007, all of the TSSA and OHSA charges laid against EGD were dismissed by the Ontario Court of Justice. The decision has been appealed by the Crown to the Ontario Superior Court of Justice and the appeal was heard by the Court during November and December 2009. The Court's decision has been reserved and EGD expects it to be released in early 2010. EGD does not believe any fines that may be levied would have a material financial impact on EGD.

EGD has also been named as a defendant in a number of civil actions related to the explosion. All significant civil actions have been settled without any material financial impact on EGD. A Coroner's Inquest in connection with the explosion is also possible.

OTHER TAX MATTERS

Enbridge and its subsidiaries maintain tax liabilities related to uncertain tax positions. While fully supportable in the Company's view, these tax positions, if challenged by tax authorities, may not be fully sustained on review.

OTHER LITIGATION

The Company and its subsidiaries are subject to various other legal and regulatory actions and proceedings which arise in the normal course of business, including interventions in regulatory proceedings and challenges to regulatory approvals and permits by special interest groups. While the final outcome of such actions and proceedings cannot be predicted with certainty, Management believes that the resolution of such actions and proceedings will not have a material impact on the Company's consolidated financial position or results of operations.

32. Guarantees

Enbridge Energy Company, Inc. (EEC), a subsidiary of the Company and the general partner of EEP, has agreed to indemnify EEP from and against substantially all liabilities, including liabilities relating to environmental matters, arising from operations prior to the transfer of its pipeline operations to EEP in 1991. This indemnification does not apply to amounts that EEP would be able to recover in its tariff rates if not recovered through insurance or to any liabilities relating to a change in laws after December 27, 1991.

In addition, in the event of default, EEC is subject to recourse with respect to US$62 million of EEP's long-term debt at December 31, 2009 (2008–US$93 million).

The Company has also agreed to indemnify EEM for any tax liability related to EEM's formation, management of EEP and ownership of i-units of EEP. The Company has not made any significant payment under these tax indemnifications. The Company does not believe there is a material exposure at this time.

In the normal course of conducting business, the Company enters into agreements which indemnify third parties. The Company cannot reasonably estimate the maximum potential amounts that could become payable to third parties under these agreements; however, historically, the Company has not made any significant payments under these indemnification provisions. While many of these agreements may specify a maximum potential exposure, or a specified duration to the indemnification obligation, there are circumstances where the amount and duration are unlimited. Examples of such indemnification obligations include the following.

Sale Agreements for Assets or Businesses:

- breaches of representations, warranties or covenants;
- loss or damages to property;
- environmental liabilities;
- changes in laws;
- valuation differences;
- litigation; and
- contingent liabilities.

Provision of Services and Other Agreements:

- breaches of representations, warranties or covenants;
- changes in laws;
- intellectual property rights infringement; and
- litigation.

When disposing of assets or businesses, the Company may indemnify the purchaser for certain tax liabilities incurred while the Company owned the assets or for a misrepresentation related to taxes that result in a loss to the purchaser. Similarly, the Company may indemnify the purchaser of assets for certain tax liabilities related to those assets.

33. United States Accounting Principles

These consolidated financial statements have been prepared in accordance with Canadian GAAP. The effects of significant differences between Canadian GAAP and U.S. GAAP for the Company are described below.

EARNINGS

Year ended December 31,	2009	2008	2007
(millions of Canadian dollars, except per share amounts)			
Earnings under Canadian GAAP Applicable to Common Shareholders	**1,555**	1,321	700
Earnings under Canadian GAAP	**1,562**	1,328	707
Inventory valuation adjustment, net of tax [3]	**(24)**	–	–
Earnings attributable to non-controlling interests under Canadian GAAP	**37**	56	46
Earnings as a result of consolidating EEP under U.S. GAAP [6]	**177**	278	168
Earnings under U.S. GAAP	**1,752**	1,662	921
Attributable to			
Enbridge Inc. [1]	**1,538**	1,328	707
Non-controlling interests [1]	**214**	334	214
Earnings under U.S. GAAP	**1,752**	1,662	921
Earnings per Common Share attributable to Enbridge Inc.	**4.71**	3.67	1.97
Diluted Earnings per Common Share attributable to Enbridge Inc.	**4.68**	3.64	1.95

COMPREHENSIVE INCOME

Year ended December 31,	2009	2008	2007
(millions of Canadian dollars, except per share amounts)			
Earnings under U.S. GAAP	**1,752**	1,662	921
Other comprehensive income/(loss) under Canadian GAAP	**(576)**	318	(197)
Underfunded pension adjustment, net of tax [5]	**3**	(57)	23
Other comprehensive income attributable to non-controlling interests under Canadian GAAP	**(72)**	101	(92)
Other comprehensive income as a result of consolidating EEP under U.S. GAAP [6]	**(62)**	241	(81)
Comprehensive income under U.S. GAAP	**1,045**	2,265	574
Attributable to			
Enbridge Inc. [1]	**965**	1,589	533
Non-controlling interests [1]	**80**	676	41
Comprehensive income under U.S. GAAP	**1,045**	2,265	574

FINANCIAL POSITION

December 31,	2009 Canada	2009 United States	2008 Canada	2008 United States
(millions of Canadian dollars)				
Assets				
Current Assets				
Cash and cash equivalents [2,6]	**327**	**478**	542	961
Accounts receivable and other [2,6]	**2,484**	**2,848**	2,322	3,175
Inventory [2,3,6]	**784**	**824**	845	911
	3,595	**4,150**	3,709	5,047
Property, Plant and Equipment, net [2,6]	**18,850**	**26,837**	16,157	24,738
Long-Term Investments [2,6]	**2,312**	**228**	2,492	412
Deferred Amounts and Other Assets [2,4,5,6]	**2,425**	**2,478**	1,318	2,080
Intangible Assets [6]	**488**	**575**	458	334
Goodwill [6]	**372**	**719**	389	808
Future Income Taxes [8]	**127**	**148**	178	178
	28,169	**35,135**	24,701	33,597
Liabilities and Shareholders' Equity				
Current Liabilities				
Short-term borrowings	**508**	**508**	874	874
Accounts payable and other [2,6]	**2,463**	**3,178**	2,411	3,203
Interest payable [6]	**104**	**151**	102	143
Current maturities of long-term debt	**601**	**633**	534	534
Current maturities of non-recourse long-term debt [2,6]	**113**	**131**	185	706
	3,789	**4,601**	4,106	5,460
Long-Term Debt [4,6]	**11,581**	**15,647**	10,155	10,257
Non-Recourse Long-Term Debt [2,6]	**1,393**	**1,399**	1,474	5,448
Other Long-Term Liabilities [2,5,6,9]	**1,207**	**1,311**	259	398
Future Income Taxes [2,4,5,6,8]	**2,211**	**2,147**	1,291	2,014
	20,181	**25,105**	17,285	23,577
Non-Controlling Interests [1,6]	**727**	**–**	797	–
Shareholders' Equity				
Share capital				
Preferred shares	**125**	**125**	125	125
Common shares	**3,379**	**3,379**	3,194	3,194
Contributed surplus	**54**	**–**	38	–
Retained earnings [3]	**4,400**	**4,343**	3,383	3,351
Additional paid in capital	**–**	**98**	–	82
Accumulated other comprehensive income/(loss) [4]	**(543)**	**(646)**	33	(72)
Reciprocal shareholding	**(154)**	**(154)**	(154)	(154)
	7,261	**7,145**	6,619	6,526
Total Enbridge Inc. Liabilities and Shareholders' Equity	**28,169**	**32,250**	24,701	30,103
Non-Controlling Interests [1,6]	**–**	**2,885**	–	3,494
	28,169	**35,135**	24,701	33,597

1 ***Presentation of Non-Controlling Interests*** *Under Canadian GAAP earnings attributable to non-controlling interests are presented as part of earnings on the income statement and the non-controlling interest balance is presented as a liability on the balance sheet. Under U.S. GAAP, the earnings and retained earnings attributable to non-controlling interests are presented as a separate component of equity.*

For the year ended December 31, 2009, $214 million (2008–$334 million; 2007–$214 million) of earnings are attributable to non-controlling interests.

Included in OCI for the year ended December 31, 2009 is an unrealized loss on cash flow hedges of $62 million (2008–$241 million unrealized gain; 2007–$81 million unrealized loss), a decrease in currency translation adjustment of $71 million (2008–$81 million increase; 2007–$61 million decrease) and an after-tax change in OCI of $1 million (2008–$20 million; 2007–$31 million) attributable to non-controlling interests.

2 **Accounting for Joint Ventures** Canadian GAAP requires that investments in joint ventures are proportionately consolidated. U.S. GAAP requires the Company's investments in joint ventures to be accounted for using the equity method. However, under an accommodation of the United States Securities and Exchange Commission, accounting for jointly controlled investments need not be reconciled from Canadian to U.S. GAAP if the joint venture is jointly controlled by all parties having an equity interest in the entity. Joint ventures in which all owners do not share joint control are reconciled to U.S. GAAP. The different accounting treatment affects only presentation and classification and not earnings or shareholders' equity. Additional information related to the Company's investments in joint ventures is included in Note 10, Joint Ventures.

3 **Commodity Inventories Valuation** Under Canadian GAAP commodity inventories are recorded at fair value. U.S. GAAP requires that commodity inventories be recorded at the lower of cost or market. For the year ended December 31, 2009, lower of cost or market adjustments resulted in a $36 million decrease to inventory, a $12 million decrease to the future income tax liability and a $24 million decrease to earnings. There were no lower of cost or market adjustments related to commodity inventory valuation for the years ended December 31, 2008 and 2007.

4 **Transaction Costs** Under Canadian GAAP transaction costs arising from the issuance of debt are recorded in Long-Term Debt. For U.S. GAAP, these costs are reclassified to Deferred Amounts and Other Assets. As at December 31, 2009, $98 million (2008–$102 million) of transaction costs were reclassified.

5 **Pension Funding Status** U.S. GAAP requires an employer to recognize the overfunded or underfunded status of a defined benefit post retirement plan or OPEB plan as an asset or liability and to recognize changes in the funded status in the period in which they occur through comprehensive income while Canadian GAAP does not require the recognition of the defined benefit post retirement plan or OPEB plan funding status.

Pension funding status adjustments resulted in an increase in the net liability of $155 million (2008–$159 million) for the underfunded status of the plans, a decrease in future tax liability of $52 million (2008–$54 million) and an increase in accumulated other comprehensive loss of $103 million (2008–$105 million) at December 31, 2009.

Amounts removed from OCI and recognized as components of the net pension and OPEB costs in the year are as follows:

	2009	2008	2007
(millions of Canadian dollars)			
Prior service cost	2	1	1
Net transitional obligation	(1)	(1)	(1)
Net loss	22	1	3
	23	1	3

Amounts included in AOCI that have not yet been recognized as a component of net periodic benefit cost are as follows:

	2009	2008	2007
(millions of Canadian dollars)			
Prior service cost	4	1	4
Net transitional obligation	(3)	(6)	(7)
Accumulated net loss	107	110	52
	108	105	49

Net amounts reflected in OCI for the year are as follows:

	2009	2008	2007
(millions of Canadian dollars)			
Unamortized prior service cost	3	(3)	(1)
Unamortized transitional obligation	3	1	1
Net loss/(gain)	(3)	58	(23)
	3	56	(23)

The Company estimates that approximately $15 million related to pension and OPEB plans at December 31, 2009 will be reclassified into earnings in the next twelve months, as follows:

	Pension Benefits	OPEB	Total
(millions of Canadian dollars)			
Net transitional obligation	(2)	1	(1)
Prior service costs	1	–	1
Loss	14	1	15
	13	2	15

6 **Consolidation of a Limited Partnership** Under U.S. GAAP the Company is deemed to have control of EEP and therefore consolidates its 27% interest in the partnership, resulting in an increase to both assets and liabilities of $6,974 million at December 31, 2009 (2008–$8,248 million) and no recognition or measurement changes to equity or earnings as at and for the year ended December 31, 2009.

7 **Unrecognized Tax Benefits**

	2009	2008
(millions of Canadian dollars)		
Unrecognized Tax Benefits at beginning of year	13	61
Gross increases for tax positions of current year	5	33
Gross increases for tax positions of prior years	6	–
Gross decreases for tax positions of prior years	(1)	(82)
Changes in translation of foreign currency	(1)	1
Unrecognized Tax Benefits at end of year	22	13

The unrecognized tax benefits at December 31, 2009, if recognized, would affect the Company's effective income tax rate. Gross increases in 2008 include a $32 million charge for the United States tax litigated matter, to unrecognize all of the tax benefits. As an unfavourable court decision was rendered in 2008, the full tax benefit balance of $65 was reversed and the unrecognized benefits removed as reflected in 2008 gross decreases. The Company does not anticipate further adjustments to the unrecognized tax benefits during the next twelve months that would have a material impact on its consolidated financial statements.

The Company recognizes accrued interest and penalties related to unrecognized tax benefits as a component of income tax expense. Income tax expense for the year ended December 31, 2009 includes $1 million (2008–$2 million) of interest. As at December 31, 2009, interest and penalties of $10 million (2008–$9 million) have been accrued.

The Company and its subsidiaries are subject to either Canadian federal and provincial income tax, United States federal, state and local income tax, or the relevant income tax in other international jurisdictions. The Company has substantially concluded all Canadian federal and provincial income tax matters for the years through 2002 and all returns are generally closed through 2004. Generally, all United States federal income tax returns and state and local income tax returns are closed through 2005 for all tax matters with the exception of the previously litigated matter. Various Canadian federal and provincial income tax returns for 2006 and 2007 are currently under examination by the Canada Revenue Agency.

8 ***Future Income Taxes*** *Under U.S. GAAP, deferred income tax liabilities are recorded for rate-regulated operations, which follow the taxes payable method for ratemaking purposes. As these deferred income taxes are expected to be recoverable in future revenues, a corresponding regulatory asset is also recorded. These assets and liabilities are adjusted to reflect changes in enacted income tax rates. At December 31, 2008, a deferred tax liability of $803 million was recorded for U.S. GAAP purposes and reflects the difference between the carrying value and the tax basis of property, plant and equipment. Effective January 1, 2009, the Canadian GAAP exemption which precluded rate regulated entities from recognizing future income taxes was removed.*

9 ***Indefinite Reversal Rule*** *The Company has not provided future taxes on the unremitted earnings of foreign investments that the Company does not intend to repatriate in the foreseeable future. These earnings relate to ongoing operations and as at December 31, 2009 were approximately $460 million (2008–$428 million).*

NEW ACCOUNTING STANDARDS UNDER U.S. GAAP

Fair Value Measurements

In September 2006, the Financial Accounting Standards Board (FASB) issued a statement that defines fair value, establishes a framework for measuring fair value in the context of GAAP and expands the disclosure requirements surrounding fair value measurement. In January 2008, the FASB deferred the implementation of this standard for all non-financial assets and non-financial liabilities, except those that are recognized or disclosed at fair value in the financial statements on a recurring basis, until January 1, 2009. The Company adopted this standard for those assets and liabilities recognized or disclosed at fair value in the financial statements on a recurring basis as of January 1, 2008 and the aspects of the standard for non-financial assets and liabilities as of January 1, 2009.

Business Combinations

In December 2007, the FASB issued a revised statement related to business combinations. This statement retains the fundamental requirements in the original statement, requiring that the acquisition method of accounting be used for all business combinations and for an acquirer to be identified for each business combination. The statement revises how the acquisition method is applied when measuring and recognizing certain items acquired. The Company adopted this standard on January 1, 2009.

Accounting for Non-Controlling Interests

In December 2007, the FASB issued a statement related to the classification of non-controlling interests in consolidated financial statements. The statement requires non-controlling interests in subsidiaries to be reported as equity on the Statement of Financial Position and requires comprehensive income attributable to non-controlling interests to be disclosed. The standard only impacts presentation and does not impact the recognition or measurement of amounts related to non-controlling interests. The Company adopted this standard on January 1, 2009.

Derivative Instrument and Hedging Activities Disclosures

In March 2008, the FASB issued a statement revising disclosure requirements for derivative instruments and hedging activities. The standard impacts presentation only and does not impact the recognition or measurement of amounts related to derivative instruments and hedging activities. The Company adopted this standard on January 1, 2009.

FUTURE ACCOUNTING STANDARDS UNDER U.S. GAAP

The following standards will be effective for the Company beginning on January 1, 2010. Management does not expect the adoption of any of these standards to significantly impact the consolidated financial statements.

Consolidation of Variable Interest Entities

In June 2009, the FASB issued a statement revising the existing statement on *Consolidation of Variable Interest Entities*. The revised Statement focuses on a qualitative approach and requires the re-assessment of existing arrangements on an on-going basis.

Accounting for Transfers of Financial Assets

In June 2009, the FASB issued a statement amending the existing statement on *Transfers of Financial Assets and Extinguishments of Liabilities*. The amended standard eliminates the qualifying special purpose entity concept, imposes stricter sale criteria, revises the de-recognition criteria and provides guidance on determining gains or losses when a transfer qualifies as a sale.

GLOSSARY

AcSB	Canadian Accounting Standards Board
AEDC	allowance for equity funds used during construction
AFUDC	allowance for funds used during construction
Alliance	Alliance System
AOCI	accumulated other comprehensive income
AROs	asset retirement obligations
ASAP	Alberta Saline Aquifer Project
bcf	billion cubic feet
bcf/d	billion cubic feet per day
bpd	barrels per day
bps	basis points
CAPP	Canadian Association of Petroleum Producers
CEAA	Canadian Environmental Assessment Agency
CICA	Canadian Institute of Chartered Accountants
CIS	customer information system
CLH	Compañía Logística de Hidrocarburos CLH, S.A.
CO_2	carbon dioxide
COSO	Committee of Sponsoring Organizations of the Treadway Commission
CSR	Corporate Social Responsibility
CustomerWorks	CustomerWorks Limited Partnership
EaR	earnings at risk
ECS	Enbridge Commercial Services Inc.
EECI	Enbridge Energy Company, Inc.
EELP	Enbridge Energy, L.P.
EEM	Enbridge Energy Management, L.L.C.
EEP	Enbridge Energy Partners, L.P.
EGD	Enbridge Gas Distribution Inc.
EGNB	Enbridge Gas New Brunswick
EIF	Enbridge Income Fund
EIFH	Enbridge Income Fund Holdings
Enbridge	Enbridge Inc.
EPI	Enbridge Pipelines Inc.
ERCB	Energy Resources Conservation Board
EUB	New Brunswick Energy and Utilities Board
FERC	Federal Energy Regulatory Commission
GAAP	Generally Accepted Accounting Principles
Gaz Metro	Gaz Metro Limited Partnership
GHG	greenhouse gases
GP	general partner
IASB	International Accounting Standards Board
IFRS	International Financial Reporting Standards
IR	incentive regulation
ISO	incentive stock option
ITS	incentive tolling settlement
JRP	Joint Review Panel
KPC	Kansas Pipeline Company
LNG	liquefied natural gas
LOI	Letter(s) of Intent
LSr Pipeline	new 20-inch diameter light sour crude oil pipeline being constructed in conjunction with the Southern Lights Pipeline
MD&A	Management's Discussion and Analyis
MDQ	maximum daily quantity
mmcf/d	million cubic feet per day
MW	megawatt
MW/H	megawatt per hour
NEB	National Energy Board
NGLs	natural gas liquids
Noverco	Noverco Inc.
NTP	NetThruPut
NYSE	New York Stock Exchange
OCENSA	Oleoducto Central S.A.
OCI	other comprehensive income
OEB	Ontario Energy Board
Offshore	Enbridge Offshore Pipelines
OHSA	Ontario Occupational Health and Safety Act
OPEB	other post-employment benefits
PBSO	performance based stock option
PSU	performance stock unit
ROE	return on equity
RSU	restricted stock unit
SEP	system expansion program
SIFT	specified investment flow-through entity
SSM	shared savings mechanism
TBD	to be determined
the Company	Enbridge Inc.
TRV	Transportation Revenue Variance
TSSA	Ontario Technical Standards and Safety Act
WCSB	Western Canada Sedimentary Basin
WRGGS	Walker Ridge Gas Gathering System

FIVE-YEAR CONSOLIDATED HIGHLIGHTS

	2009	2008	2007	2006	2005
(millions of Canadian dollars, except per share amounts)					
Earnings Applicable to Common Shareholders					
Liquids Pipelines	**445**	328	287	274	229
Natural Gas Delivery and Services	**635**	958	344	323	326
Sponsored Investments	**141**	111	97	87	65
Corporate	**334**	(76)	(28)	(69)	(64)
	1,555	1,321	700	615	556
Earnings per Common Share	**4.27**	3.67	1.97	1.81	1.65
Diluted Earnings per Common Share	**4.25**	3.64	1.95	1.79	1.63
Adjusted Earnings [1]					
Liquids Pipelines	**454**	332	286	274	229
Natural Gas Delivery and Services	**289**	302	324	322	309
Sponsored Investments	**151**	101	86	75	61
Corporate	**(39)**	(58)	(59)	(78)	(62)
	855	677	637	593	537
Adjusted Earnings per Common Share [1]	**2.35**	1.88	1.79	1.74	1.59
Cash Flow Data					
Cash provided by operating activities	**2,017**	1,372	1,362	1,298	947
Cash used in investing activities	**(3,306)**	(2,853)	(2,229)	(1,580)	(877)
Cash provided by/(used in) financing activities	**1,109**	1,840	904	268	(22)
Dividends					
Common Share Dividends Declared	**555**	489	453	403	361
Dividends per Common Share	**1.48**	1.32	1.23	1.15	1.04
Shares Outstanding *(millions)*					
Weighted average common shares outstanding	**364**	360	355	340	337
Diluted weighted average common shares outstanding	**366**	363	358	343	341

1 Adjusted earnings represent earnings applicable to common shareholders adjusted for non-recurring or non-operating factors. Adjusted earnings and adjusted earnings per common share are non-GAAP measures that do no thave any standardized meaning prescribed by GAAP. For more information on non-GAAP measures see pages 36 and 102.

FIVE-YEAR CONSOLIDATED HIGHLIGHTS

	2009	2008	2007	2006	2005
(per share amounts in Canadian dollars)					
Common Share Trading (TSX)					
High	**48.92**	46.27	41.48	41.45	38.82
Low	**35.20**	33.10	33.62	31.75	28.59
Close	**48.63**	39.56	40.01	40.27	36.34
Volume *(millions)*	**228**	293	204	174	211
Financial Ratios					
Return on average shareholders' equity [1]	**22.2%**	22.2%	13.6%	13.9%	13.2%
Return on average capital employed [2]	**8.9%**	9.9%	7.0%	7.0%	6.9%
Debt to debt plus shareholders' equity [3]	**66.2%**	66.6%	66.5%	68.9%	68.9%
Earnings coverage of interest [4]	**3.6x**	3.8x	2.4x	2.4x	2.4x
Dividend payout ratio [5]	**63.0%**	70.2%	68.7%	66.1%	65.2%
Operating Data					
Liquids Pipelines–Average Deliveries *(thousands of barrels per day)*					
Enbridge System [6]	**2,061**	2,030	2,005	2,013	1,872
Enbridge Regional Oil Sands System [7]	**259**	202	164	190	142
Spearhead Pipeline	**121**	110	103	82	–
Olympic Pipeline	**280**	291	284	289	–
Natural Gas Delivery and Services					
Gas Pipelines–Average Throughput Volumes *(millions of cublic feet per day)*					
Alliance Pipeline US	**1,601**	1,609	1,598	1,592	1,597
Vector Pipeline	**1,334**	1,321	1,034	1,015	1,033
Enbridge Offshore Pipelines	**2,037**	1,672	2,060	2,153	2,102
Enbridge Gas Distribution					
Volumes *(billions of cubic feet)*	**408**	433	440	408	439
Number of active customers [8] *(thousands)*	**1,937**	1,898	1,861	1,820	1,774
Degree day deficiency [9]					
Actual	**3,767**	3,802	3,659	3,355	3,750
Forecast based on normal weather	**3,514**	3,543	3,617	3,745	3,747

1 *Earnings applicable to common shareholders divided by average shareholders' equity (weighted monthly during the year).*

2 *Sum of after-tax earnings and after-tax interest expense, divided by weighted average capital employed. Capital employed is equal to the sum of shareholders' equity, EGD preferred shares, future income taxes, deferred credits and total debt (including short-term borrowings).*

3 *Total debt (including short-term borrowings) divided by the sum of total debt and shareholders' equity.*

4 *Earnings before income taxes and interst expense divided by interest expense (including capitalized interest).*

5 *Dividends per common share divided by adjusted earnings per common share.*

6 *Enbridge System includes Canadian mainline deliveries in Western Canada and to the Lakehead System at the United States border as well as Line 8 and Line 9 in Eastern Canada.*

7 *Volumes are for the Athabasca mainline and the Waupisoo Pipeline and do not include laterals on the Enbridge Regional Oil Sands System.*

8 *Number of active customers is the number of natural gas consuming EGD customers at the end of the year.*

9 *Degree day deficiency is a measure of coldness which is indicative of volumetric requirements for natural gas utilized for heating purposes in EGD's franchise area. It is calculated by accumulating, for the fiscal year, the total number of degrees each day by which the daily mean temperature falls below 18 degrees Celsius. The figures given are those accumulated in the Greater Toronto Area.*

ENBRIDGE BUSINESSES

LIQUIDS PIPELINES

Enbridge Pipelines Inc. (100%)

Enbridge Pipelines (NW) Inc. (100%)

Enbridge Pipelines (Athabasca) Inc. (100%)

Enbridge Pipelines (Toledo) Inc. (100%)

Enbridge Southern Lights L.L.C. (100%)

Enbridge Midstream Inc. (100%)

Gateway Pipeline Limited Partnership (100%)

Mustang Pipe Line Partners (30%)

Chicap Pipe Line Company (43.8%)

Frontier Pipeline Company (77.8%)

CCPS Transportation L.L.C. (Spearhead Pipeline) (100%)

Olympic Pipe Line Company (65%)

Hardisty Caverns Limited Partnership (50%)

NATURAL GAS DELIVERY AND SERVICES

Enbridge Gas Distribution (100%)

- St. Lawrence Gas Company, Inc. (100%)

Gazifere Inc. (100%)

Niagara Gas Transmission Limited (100%)

Noverco Inc. (32.1%), which owns:

- Gaz Métro Limited Partnership (71%), which owns:
  - Vermont Gas Systems, Inc. (100%)
  - TQM Pipeline and company, Limited Partnership (50%)
  - Portland Natural Gas Transmission System (38.3%)

Enbridge Gas New Brunswick Limited Partnership (70.9%)

CustomerWorks Limited Partnership (70%)

Enbridge Commercial Services Inc. (100%)

Aux Sable Liquids Products Inc. (42.7%)

Enbridge Gas Services (U.S.) Inc. (100%) [1]

Tidal Energy Marketing (U.S.) L.L.C. (100%) [1]

Enbridge Gas Services Inc. (100%) [2]

Tidal Energy Marketing Inc. (100%) [2]

Rabaska Limited Partnership (33%)

Alliance Pipeline L.P. (Alliance Pipeline U.S.) (50%)

Vector Pipeline Limited Partnership (60%)

Enbridge Offshore Pipelines, L.L.C. (22% – 100%)

Enbridge Technology Inc. (100%)

SPONSORED INVESTMENTS

Enbridge Energy Partners, L.P. (27%)

- Lakehead System
- North Dakota System
- Mid-Continent System
- Various Natural Gas Systems

Enbridge Energy, L.P. (66.7% interest in Series AC units)

Enbridge Income Fund (72% economic interest; 41.9% voting interest)

- Enbridge Pipelines (Saskatchewan) Inc. (100%)
- Alliance Pipeline Limited Partnership (Alliance Pipeline Canada) (50%)
- SunBridge Wind Power Project (50%)
- Magrath Wind Power Project (33.3%)
- Chin Chute Wind Power Project (33.3%)
- NRGreen Power Limited Partnership (50%)

CORPORATE

Enbridge Ontario Wind Power Project L.P. (100%)

FuelCell Energy (strategic alliance)

Sarnia Solar Project L.P. (100%)

Talbot Windfarm L.P. (90%)

1 *Effective January 1, 2010, Enbridge Gas Services (U.S.) Inc. was amalgamated with Tidal Energy Marketing (U.S.) L.L.C.*

2 *Effective January 1, 2010, Enbridge Gas Services Inc. was amalgamated with Tidal Energy Marketing Inc.*

2009 AWARDS AND RECOGNITION

Alberta's Top Employers

Alberta's Top Employers is an annual competition organized by the editors of Canada's Top 100 Employers in partnership with the Human Resources Institute of Alberta (HRIA). The award recognizes companies for best practices in recruitment and retention.

Alberta Venture's Most Respected Corporations

Alberta Venture readers selected Enbridge as one of Alberta's top three organizations in the category of Corporate Financial Performance. Over 4,200 corporate peers provided their input into the survey, making it one of the most credible gauges of business perspectives in Alberta.

Canada's 10 Most Admired Corporate Cultures

Waterstone Human Capital recognized Enbridge with its Canada's 10 Most Admired Corporate Cultures award (Natural Resources category) for having a culture that enhances financial performance and sustains a competitive advantage.

Canada's Top 100 Employers:

Mediacorp Canada recognized Enbridge as being one of Canada's top employers and for being an industry leader in attracting and retaining employees.

Corporate Knights Best 50 Corporate Citizens in Canada

Corporate Knights recognized Enbridge as being one of Canada's Best 50 Corporate Citizens. The ranking is the longest running of its kind and is determined based on a thorough analysis of contenders' stakeholder performance according to publicly available information.

Dow Jones Sustainability Index (North America)

The Dow Jones Sustainability Index recognized Enbridge for excellence in sustainability performance. The index reviews the sustainability performance of the top 20% of the 600 largest companies in North America.

Environmental Award of Excellence (Green Toronto Energy Conservation Awards)

The Green Toronto Energy Conservation Awards recognized Enbridge Gas Distribution's (EGD) efforts to reduce energy and to develop renewable energy sources to improve air quality. EGD received the award for its work on building an innovative hybrid fuel cell plant that produces electricity with virtually no emissions.

Forbes.com Most Trustworthy Companies

Forbes.com's list of Most Trustworthy Companies recognized Enbridge Energy Partners (EEP) for its accounting and governance practices. EEP was included on the list because it achieved the highest audit integrity ratings for accounting and governance risk.

Fortune 500 America's Largest Corporations

Enbridge Energy Partners was listed 343 on the Fortune 500 ranking of America's Largest Corporations, earning the fourth spot in the pipeline industry.

Fortune Magazine's World's Most Admired Companies

Fortune magazine ranked Enbridge Energy Partners (EEP) fifth in the pipeline industry category of its World's Most Admired Companies list. This list is considered to be the definitive report card on corporate reputation, and EEP has been included in the top five for the third straight year.

Gold Champion Level Reporter (Canadian Standards Association's GHG Registry)

The Canadian Standards Association awarded Enbridge Gold Champion Level Reporter status for its greenhouse gas emissions reporting.

Natural Gas STAR Program (U.S. Environmental Protection Agency)

The Natural Gas STAR Program is a voluntary partnership that encourages oil and natural gas companies to adopt cost-effective technologies and practices that improve operational efficiency and reduce methane emissions. Enbridge Inc. received the Natural Gas STAR International Partner of the Year award. Enbridge Energy Partners was honoured as a Natural Gas STAR for continuing excellence, recognizing its five-year participation in the voluntary program.

Toronto Star, Greenest Companies in Canada

The *Toronto Star* ranked Enbridge Gas Distribution as one of the eight greenest companies in Canada for its emphasis on energy conservation and alternative energy generation.

INVESTOR INFORMATION

Common and Preferred Shares

The Common Shares of Enbridge Inc. trade in Canada on the Toronto Stock Exchange and in the United States on the New York Stock Exchange under the trading symbol "ENB". The Preferred Shares, Series A, of Enbridge Inc. trade in Canada on the Toronto Stock Exchange under the trading symbol "ENB.PR.A".

Registrar and Transfer Agent in Canada

CIBC Mellon Trust Company
P.O. Box 7010,
Adelaide Street Postal Station
Toronto, Ontario M5C 2W9
Toll free: 800.387.0825
Internet: www.cibcmellon.com/investorinquiry
CIBC Mellon Trust Company also has offices in Halifax, Montreal, Calgary and Vancouver.

Co-Registrar and Co-Transfer Agent in the United States

BNY Mellon Shareowner Services
480 Washington Blvd.
Jersey City, New Jersey
U.S.A. 07310
Toll free: 800.387.0825
Internet: www.cibcmellon.com/investorinquiry

Debentures and Notes — Registrars and Trustees:

The registrar and trustee for Enbridge Debentures is Computershare Trust Company of Canada, with offices in Montreal, Toronto, Winnipeg, Calgary, Halifax and Vancouver.

Auditors

PricewaterhouseCoopers LLP

Dividend Reinvestment and Share Purchase Plan, and Dividend Direct Deposit

Enbridge Inc. offers a Dividend Reinvestment and Share Purchase Plan that enables shareholders to reinvest their cash dividends in Common Shares and to make additional cash payments for purchases at the market price. Effective with dividends payable on March 1, 2008, participants in the Plan will receive a two per cent discount on the purchase of common shares with reinvested dividends. The Company also offers Dividend Direct Deposit which enables shareholders to receive dividends by electronic fund transfe to the bank account of their choice in Canada. Details may be obtained from the Investor Information section of the Enbridge website at or by contacting CIBC Mellon Trust Company at any of the locations listed above.

New York Stock Exchange Disclosure Differences

As a foreign private issuer, Enbridge Inc. is required to disclose any significant ways in which its corporate governance practices differ from those followed by United States companies under NYSE listing standards. This disclosure can be obtained from the U.S. Compliance subsection of the Corporate Governance section of the Enbridge website at www.enbridge.com.

Form 40-F

The Company files annually with the United States Securities and Exchange Commission a report known as the Annual Report on Form 40-F. Copies of the Form 40-F are available, free of charge, upon written request to the Corporate Secretary of the Company. In addition a link to it is available on the "Reports and Filings" subsection of the "Financial Reports" section of our website.

Corporate Social Responsibility Report

Enbridge publishes an annual Corporate Social Responsibility report. The 2009 report is available on the Company's website at www.enbridge.com/csr2009.

Registered Office

Enbridge Inc.
3000, 425–1st Street S.W.
Calgary, Alberta, Canada T2P 3L8
Telephone: 403.231.3900
Facsimile: 403.231.3920
Internet: www.enbridge.com

Shareholder Inquiries

If you have inquiries regarding the following:

- Dividend Reinvestment and Share Purchase Plan
- change of address
- share transfer
- lost certificates
- dividends
- duplicate mailings

please contact the registrar and transfer agent—CIBC Mellon Trust Company in Canada or BNY Mellon Shareowner Services in the United States.

Other Investor Inquiries

If you have inquiries regarding the following:

- additional financial or statistical information
- industry and company developments
- latest news releases or investor presentations
- any other investment-related inquiries

please contact Enbridge Investor Relations or visit Enbridge's website at www.enbridge.com.

Investor Relations

Enbridge Inc.
3000, 425–1st Street S.W.
Calgary, Alberta, Canada T2P 3L8
Toll free: (800) 481-2804

Annual Meeting

The Annual Meeting of Shareholders will be held in the Ballroom of the Metropolitan Centre, Calgary, Alberta at 1:30 p.m. MST on Wednesday, May 5, 2010. A live audio webcast of the meeting will be available at www.enbridge.com and will be archived on the site for approximately one year. Webcast details will be available on the Company's website closer to the meeting date.

Le présent document est disponible en français.

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2010 Enbridge Inc. Common Share Dividends

	1st Q	2nd Q	3rd Q	4th Q
Dividend	$0.425	$–	$–	$–
Payment date	Mar. 1	Jun. 1	Sep. 1	Dec. 1
Record date [1]	Feb. 15	May 14	Aug. 13	Nov. 15
Board declaration	Dec. 2/09	May 4	July 27	Nov. 2
SPP deadline [3]	Feb. 22	May 25	Aug. 25	Nov. 24
DRIP enrollment [2]	Feb. 8	May 7	Aug. 6	Nov. 8

1 *Dividend Record Dates for Common Shares are generally February 15, May 15, August 15 and November 15 in each year; however, record date is accelerated for weekends and adjusted to accommodate the Annual General Meeting date.*

2 *The Dividend Reinvestment Program Enrollment Cut-off Date is five business days prior to the Dividend Record Date.*

3 *The Share Purchase Plan Cut-off Date is five business days prior to the Dividend Payment Date.*

ENBRIDGE

Enbridge Inc., a Canadian company, is a North American leader in delivering energy. As a transporter of energy, Enbridge operates, in Canada and the United States, the world's longest crude oil and liquids transportation system. The Company also has a growing involvement in the natural gas transmission and midstream businesses and is expanding its interests in renewable and green energy technologies, including wind and solar energy, hybrid fuel cells and carbon dioxide sequestration. As a distributor of energy, Enbridge owns and operates Canada's largest natural gas distribution company and provides distribution services in Ontario, Quebec, New Brunswick and New York State. Enbridge employs approximately 6,000 people, primarily in Canada and the United States. Enbridge's common shares trade on the Toronto and New York stock exchanges under the symbol ENB.

www.enbridge.com

Affiliations, Partnerships and Accreditations

Gold™ Champion Level Reporter www.ghgregistries.ca

50 Corporate Knights • 2009 Best Corporate Citizens

Canada's Top 100 Employers 2009

Dow Jones Sustainability Indexes Member 2009/10

CARBON DISCLOSURE PROJECT

Enbridge common shares trade on the Toronto Stock Exchange in Canada and on the New York Stock Exchange in the United States under the trading symbol ENB.

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